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The Habitat and Cost of Production of Domestic Petroleum Resources.

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THE HABITAT AND COST OF PRODUCTION OF DOMESTIC PETROLEUM RESOURCES

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Abstract

The geologic characteristics of an oil field, most importantly its depth and surface area, have significant impacts on the average const of extracting petroleum. These characteristics of petroleum habitat constitute a measure of "deposit quality," as ore grade does in the production of metals. This measure can be used to separately evalute the effects on cost, over time, of changing deposit quality and technological advance.

A sample of 156 U.S. fields, with average estimated ultimate recovery of 50 million barrels, was analyzed to quantify the cross-sectional differences in average production cost on the basis of depth, area, productive capacity, reservoir lithology and reservoir drive mechanism. Changes each year between 1942 and 1972 in the quality of new discoveries was computed on the basis of depth, surface area and productive capacity. Increasing average depth and decreasing productive capacity during the period would have produced annual increases in average cost of 2.4%, in the absence of technological change.

Using the year of field discovery to measure the variation in cost attributable to technological change, the negative influence on cost arisng from this factor exceeded the increase from declining deposit quality to produce a net decline in average cost of 0.74%/year. Statistical insignificance and inconsistency of the parameter estiaemte on technological change late in the time series indicated that the magnitude and direction of the net change in average cost may have been changing in the late 1960s. Increases in the prices of inputs, particularly capital, may have been responsible, along with the transition of the U.S. resource base from one of increasing to decreasing produciton.

Integration of field characteristics into modified Cobb-Douglas and engineering cost/production functions demonstrated the vlaue of these parameters in analysis of the variation in the average cost of extracting crude oil. The additional information produced by this approach enhances the usefulness of average cost as a indicator of scarcity of mineral resources. The research also showed that in the case of petroleum, decreases in deposit quality were not associated with increases in the physical quantity of mineral resources in place.

Chapter 1

Introduction

The objective of this research is to investigate the relationship between the natural habitat of petroleum occurrences and the average cost of extracting petroleum from them. To accomplish this, estimable cost functions for oil fields will be developed that formally introduce geologic and engineering characteristics of the fields as arguments, with the standing of labor and capital. There are two purposes for using this method. The first is to pursue a different avenue for empirical study of mineral extraction costs. Investigators have identified problems with the use of unit extraction cost as an indicator of economic scarcity; this approach may circumvent some of them. The second is to assess the value of employing physical relations and variables in modeling economic processes. If these factors play a significant role, resource supply models which omit them may be misspecified and their results biased.

Crude oil was chosen for its economic importance and because there has been no comprehensive effort to analyze the implications of changing deposit quality for cost and supply. Valuable contributions have been made demonstrating relationships between ore grade and the efficiency of producing metals.[1] Unfortunately, a broadly based univariate indicator for deposit quality, like ore grade, does not exist for petroleum. A multivariate measure

1. The general implications for declining ore grade on the production efficiency of energy and other purchased inputs has been made by Brian J. Skinner, "Second Iron Age Ahead?," American Scientist, vol. 64 (1979), pp. 258-269 and by Earl Cook, "Limits to Exploitation of Nonrenewable Resources" in Herman E. Daly, ed., Economics, Ecology, Ethics, Essays Toward A Steady State Economy (San Francisco: W.H. Freeman, 1980), pp. 82-99. Skinner reexamined the value of grade as a deposit quality indicator and added ore mineralogy in "The Frequency of Mineral Deposits," Alex. L. du Toit Memorial Lecture No. 16, (The Geological Society of South Africa, 1979)

of quality will be developed and its behavior studied. The population from which samples will be drawn consists of U.S. fields with at least 10 million barrels of recoverable oil. The fields of this size contain over 90% of the nation's oil reserves.[2]

The Cost of Extraction

Studying the costs of mineral extraction has an intrinsic and instrumental value. As in the study of any industry, developing a formal model of the production process that will support testing hypotheses about economic activity requires a concise understanding and explanation. The foundation of assumptions on which it is based must both allow the model to work and be defensibly grounded in reality. The content of the validated assumptions and the results of hypothesis tests add to what is known about the behavior of producers in the industry.

Though substantial resources have gone to study energy, particularly petroleum, most of the attention has been directed to the demand side, or on the supply side, to problems of market structure and processes downstream from crude production. The economics of crude oil production at the field and basin level is sparsely researched. There are very few studies of either production cost variation over time or cross-sectionally by producing units.[3]

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2. Richard Nehring, The Discovery of Significant Oil and Gas Fields in the United States, (Santa Monica, CA: Rand Corporation, 1981), p. vi.

3. Two important studies have been made relating the cost of producing crude to a single field characteristic. Franklin M. Fisher, Supply and Costs in the U.S. Petroleum Industry: Two Econometric Studies (Baltimore: Johns Hopkins University Press for Resources for the Future, 1964) examined the relationship for cost and reservoir depth. J.J. Arps and T.G. Roberts, "Economics of Drilling for Cretaceous Oil on East Flank of Denver-Julesburg Basin," Bulletin of the American Association of Petroleum Geologists, vol. 42, no. 11 (1959), pp. 2549-2566 measured economies of scale in producing from fields of different sizes. In addition, there have been three studies besides Arps and Roberts that have examined production costs at the basin level in

Production and cost data on petroleum production at low levels of aggregation are difficult to get, particularly for the U.S. This is the most likely cause for such a small body of research on economic aspects of U.S. crude -oil production.[4]

Because petroleum is a depletable resource, analysis of extraction costs, particularly their variation over time, has special instrumental value as an indicator of economic scarcity. In one of the first empirical studies of resource scarcity and its implications, Barnett and Morse, used changes over time in the unit cost of extraction as an "imperfect but reasonably acceptable" indicator.[5] They reasoned that as a resource became increasingly scarce, sources of lower quality would be brought into production, raising the amount of labor and capital required to produce a single unit of the product. Herfindahl concurred with this view, adding that increasing difficulty (i.e., cost) of deposit discovery would compound the influence of declining deposit quality to raise unit cost as depletion occurred.[6]

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the U. S. These are U. S. Geological Survey, "Future Supply of Oil and Gas from the Permian Basin of West Texas and Southeastern New Mexico," U.S. Geological Survey Circular 828 (1980); E.D. Attanasi and J.L. Haynes, "Future Supply of Oil and Gas from the Gulf of Mexico," U.S. Geological Survey Professional Paper 1294 (1983) and D.A. Murry and A.B.Davies, "Estimate of the Cost of Petroleum Production from the Anadarko, Hugoton-Panhandle and Frio Basin," presented at the SPE-AIME Eighth Hydrocarbon Economics and Evaluation Symposium, 1979.

4. Paul G. Bradley, The Economics of Crude Petroleum Production, (Amsterdam: North-Holland Publishing Company, 1967) used the Middle East, Africa and Venezuela for his analysis of cost. M.A. Adelman and Geoffrey L. Ward, "Worldwide Production Costs for Oil and Gas" in John R. Moroney, ed., Advances in The Economics of Energy and Resources, A Research Annual, vol. 3, (Greenwich, CN: JAI Press Inc., 1980), pp. 1-29, applied Fisher's methodology plus several other factors to make comparisons between several areas of the world, but each region was treated at a very high level of aggregation.

5. Harold J. Barnett and Chandler Morse, Scarcity and Growth, The Economics of Natural Resource Availability, (Baltimore: Johns Hopkins University Press for Resources for the Future, 1963), pp. 7-8.

Of the three classes of indicators of economic scarcity: unit extraction cost, market price, and economic rent to the resource, the first has received the greatest attention. Several limitations of this instrument have been described, raising questions about its value as a scarcity indicator. In articles by Brown and Field and by A.C. Fisher, four problems were identified:[7]

1. Costs are difficult to measure, both with respect to determining the cost to the firm and environmental externalities.

2. There may not be a stable functional relationship between extraction cost and the degree of physical scarcity of a resource, so impending exhaustion may not be signalled.

3. It is difficult to isolate the cost reducing impact of technological advances from the increases in cost attributable to falling deposit quality. If these influences are not separately identified, the change in cost over time and its effect on the economy may be mismeasured.

4. Unit extraction cost is not a leading indicator and does not reflect expectations on either future availability or extraction costs.

Only the last point involves a theoretical problem. The first three observations apply to empirical difficulties which require special consideration in designing analysis. Avoidance or mitigation of these problems

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6. Oris C. Herfindahl, Copper Costs and Prices: 1870-1957, (Baltimore: Johns Hopkins University Press for Resources for the Future, 1959), p. 1.

7. Gardner M. Brown and Barry Field, "The Adequacy of Measures for Signalling the Scarcity of Natural Resources," pp. 218-248 and Anthony C. Fisher, "Measures of Natural Resource Scarcity," pp. 249-275 in V. Kerry Smith, ed., Scarcity and Growth Reconsidered, (Baltimore: Johns Hopkins University Press for Resources for the Future, 1979).

in any particular study will enhance the informational content of unit extraction cost as an indicator of scarcity. In examining the strengths and weaknesses of unit cost, A. C. Fisher concluded that the "moral is, I think, not that we should abandon cost estimation, simply that we must recognize that it may not be a straightforward procedure."[8]

Point no. 1 is correct. It is difficult to obtain reliable cost data because much of it is proprietary and the rest, in the case of oil, was buried in government records in a large number of states. Fortunately, the surge in interest by the federal government in energy during the last ten years has lead to the collection and centralization of vast quantities of raw data on U.S. petroleum resources. This has enabled research that was impossible before the late 1970's.

Though there has been an increase in research on the environmental impacts of oil production, there is no integrated data base that would allow assignment of environmental costs at the field level. Therefore, they cannot be considered in this analysis. This is a clear limitation to the study because full assessment of the future cost and supply of mineral resources must encompass externalities. However, for crude oil production, the divergence between social and private costs may not be as great as with many other minerals. Though there can be environmental damage from drilling and surface operations, intuitively, those costs per dollar of product would seem far smaller than in open pit or even the subsurface mining techniques. Analysis of internal costs to the firm, however, does provide a minimum to which external costs could be added without revision of the present findings.

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8. A.C. Fisher, "Measures of Natural Resource Scarcity," p. 258.

Point no. 2 addresses the relationship between physical and economic scarcity. This is an important consideration, but like the first, may not be as serious a problem with petroleum as with other minerals for two reasons. First is that in the case of oil, the deposit is discrete in the earth's crust. Metal ores are the high concentration occurrences of atoms that are abundant throughout the crust. Geologic processes have enriched some areas and depleted others, but for most economically important minerals, in the limit, even common rock is a potential source if mining and benefication become cheap enough.

This is not the case with fossil fuels because their direct sources are not the abundant store of inorganic atoms of the lithosphere. Instead they are remnants of a relatively small mass of biologic organisms deposited over a relatively short segment of geologic history. This organic matter accumulated in only very specific environments and is not dispersed at a background concentration (clarke) throughout the crust. There is no real "mineralogical threshold" for oil, which if crossed will yield physical abundances that dwarf forseeable economic demands.[9] Technology and price will alter the types of <u>fields</u> that can be profitably produced, but no possibility exists of grinding common rock for oil, so the physical resource is better defined.

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9. The concept of a "mineralogical threshold" was proposed by Skinner in "Second Iron Age Coming?" and expanded in "The Frequency of Mineral Deposits." He suggested that for metals in the crust (except those with average concentrations over 0.1%: aluminum, iron, magnesium and titanium, and certain ones between 0.01% and 0.1%: barium, manganese, vanadium and zirconium), that the distribution of total quantity with respect to grade is bimodal. For the small percent of the total quantity distributed around the higher mode, the metals occur as their own discrete minerals. These are the resources we mine. The lower grade mode, around which the vast bulk of total quantity is distributed, is at a concentration near the average crustal abundance. In this case, the atoms are randomly distributed within the crystal lattices of common rocks (silicates). In the latter article, Skinner

The second reason is that for oil deposits, the contact between where the oil is and is not in a body of rock is fairly distinct. The total physical resource at the field level (original oil in place, OIP) is often known with high certainty within the first few years of production. As the degree of physical scarcity can be directly measured, it will be possible to empirically determine the relationship between extraction cost and the quantity of remaining physical resource. Historically, only 25% to 30% of OIP is produced before a field is shut down. It seems, then, that rising costs substantially anticipate physical exhaustion of oil fields. Oil is unlike the case of the fishery where improvement in catching technique drives unit cost down to a threshold where the level of production extinguishes the school and marginal cost abruptly turns to infinity.

Point no. 3 posits a need to precisely decompose variations in unit cost into reductions due to technology and increases arising from the decline in deposit quality. The necessity of such a division is not clear. The stylized effect of technological advance on production is an increase in the efficiency of one or a combination of purchased inputs. Considering the deposit itself as an input, it is the combination of deposit and purchased inputs that gives rise to the production of a marketed mineral. If the marginal product of the purchased inputs is raised by improving technology, it would be possible,

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demonstrated that this difference in mineralogical settings implies that though physical quantities increase (discontinuously) with declining grade, the potential increase in availability can be superceded by the increase in the energy required for mining and concentration of the metal atoms from silicates. With free, or nearly free energy (<u>ceteris paribus</u>), the "mineralogical threshold" could conceivably be crossed and access gained to the valuable atoms dispersed in common rock. This remote technological rescue does not, however, exist for hydrocarbons. The large, complex hydrocarbon molecules do not substitute into silicate structures the way the single atoms of many metals can.

(<u>ceteris paribus</u>), to substitute deposits of lower marginal product without raising the quantity of purchased inputs required per unit of output. As the distribution of deposits with respect to their quality (marginal product) is given in nature and the general trend is to deplete the highest quality deposits first, then the course of unit extraction cost over time reflects the <u>net</u> effect of the opposing forces. It is the net effect, not the magnitude of the components, that is important to the economy at large. It is "resource drag" on growth or the sacrifice of other goals to meet increasing extraction requirements that is the concern. If unit cost dropped as cumulative production rose (a negative stock effect), then changes in the nature of deposits over time become an almost purely academic interest.

However, embedded in the separate positive and negative effects may be information which would improve forecasting the future path of extraction costs. In the case of U.S. petroleum, there is a high level of knowledge about the quality of deposits that contain the remaining resource. This, and the variety of fields already under production can provide a broad foundation for predicting the impact of further depletion on deposit quality, cost and supply. This aspect of the present study also addresses point no. 4, that cost is generally a contemporaneous or even lagging indicator of scarcity.

Most of the oil that will ultimately be produced has, or will come from fields that have already been discovered.[10] Consequently, the qualitative characteristics of the total petroleum resource base are well known in many respects. Our future production, therefore, will be mainly on the intensive

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10. G.L. Dolton, et al, "Estimate of Undiscovered Recoverable Conventional Resources of Oil and Gas in the United States," U.S. Geological Survey Circular 860, (1981).

margin. Because this set of fields is finite, the rates of change in the aspects of average deposit quality, (e.g., depth of production, size of field, field lithology) are largely determinant functions of cumulative production. The set of fields will be enlarged by new discoveries, but even some of their qualities are known by elimination.[11] If the cost impacts of these changes (net of technological advance) can be determined now, general trends in future extraction costs may be easier to define.

Estimation of the economic consequences of eventual changes in average field depth, size and other characteristics can be made now because of the diversity of fields from which production has been drawn. Though the average depth of production has increased over time, there has usually been a significant share of production from reservoirs that are twice as deep as the average. Consequently, in estimating the impact of increasing average depth on cost, analysis of costs from the established deep fields can contribute substantially. Likewise, evaluation of the impact of the declining size of new field discoveries on future average cost and supply can be made on the basis of small fields that were produced "early" because they were perhaps shallow, or close to transportation lines.

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11. For example, the chances of finding a field the size of Prudhoe Bay (8 billion bbl. estimated ultimate recovery, EUR) in Texas or Louisiana is almost nil given the number of acres such a field occupies and the spatial density of drilling in those two states. For analysis of the impact of cumulative discoveries on the characteristics of undiscovered resources, see H. William Menard, "Toward a Rational Strategy for Oil Exploration," Scientific American, vol. 244, no. 1 (January, 1981), pp. 55-65 and L.J. Drew, E.D. Attanasi and D.R. Root, "The Importance of Physical Parameters in Petroleum Supply Models," in Mineral Policies in Transition, ed. John H. DeYoung, Jr., Proceedings of the Mineral Economics Symposium, November 8-9, 1977, Washington, D.C. (AIMMPE: 1978).

If it is possible to develop cost impact multiplies for a unit change in deposit quality, then if those changes themselves are dependent on the rate of production, it is possible to derive at least a lower bound for unit cost as a function of cumulative production. This does not overcome the theoretical problem that the determinants of unit cost do not include a forward looking component. However, in practical terms, it is felt that a contribution to understanding future extraction costs and economic scarcity can be made through this type of analysis of historical trends. The degree to which this approach to studying extraction costs overcomes or compensates for its weaknesses as a scarcity indicator will be assessed in the conclusion of the research.

Engineering Production Functions

There is no theoretical reason why the technical factors and relations surrounding an industrial process cannot be formally introduced into economic analyses of them. Usually, inputs are aggregated at a very high level, holding all technical parameters constant. Hollis Chenery, in introducing the concept of engineering production functions in 1949 suggested that "because of this inability to use engineering data as a basis for economic reasoning, a great discrepancy exists between the theoretical analysis of problems of production and the empirical studies which have been made."[12] Analysis in this tradition has made two contributions which will be exploited in this study. First is that it is the physical and chemical laws governing the production process that generate the detailed specifications of the firm's demand for purchased

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12. Hollis Chenery, "Engineering Production Functions," Quarterly Journal of Economics, vol. 63, no. 4 (November, 1949), p. 507.

inputs, particularly captial. Chenery used the example of steam generation (a process common to many industries) to illustrate the relationship between the technical and economic optimization processes.[13]

> In the process of steam generation, the output of steam per hour is a function of the rate of flow of water, the temperature, and the dimensions of the boiler. These in turn determine the pressure in the boiler, the stress in the steel, and hence the type and amount of steel required.

Translating these principles into functional forms, he offered the following relationships:

$$(1.1) \qquad u_i = u_i(v_1,\ldots,v_n) \qquad (i=1,\ldots,n)$$

$$(1.2) \qquad p_i = p_i(v_1,\ldots,v_n)$$

where,

u_i=the quantity of the physical inputs. In the example above, one of the inputs could be steel, in tons.

p_i=the unit price of u_i.

v_i=the engineering characteristics of u_i. In the example above, tensile strength, thickness, thermal properties, etc.

then where X is the product (e.g., lbs. of steam/hour) the generalized economic production function would be:

$$(1.3) \qquad X = f(u_1,\ldots,u_n)$$

Substituting Eq. 1.1 into Eq. 1.3 yields the engineering production function, with product as a function of the characteristics of the physical processes:

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13. ibid, p. 511-513.

(1.4) $$X = g(v_1,\ldots,v_n)$$

The cost function can be similarly written, where C is cost:

(1.5) $$C = \sum L_i P_i$$

so, substituting Eq. 1.1 into 1.5, the engineering cost function becomes:

(1.6) $$C = h(v_1,\ldots,v_n)$$

On the basis of 1.4 and 1.6, it is possible to conduct standard economic analysis of production and cost at the firm level.

The second innovation of this approach is the division of the production process into two distinct phases. In the first phase, the energy and material requirements of the process are established. These are determined by the physical and chemical laws relevant to the process and are hence given to the firm. In the second stage, the combination of purchased inputs needed to meet requirements determined in the first stage are chosen in proportions that minimize cost.

The relationship between this divisable optimization and the duality of production and cost functions in standard economic analysis was reviewed by Marsden, et al, in 1972.[14] They have demonstrated that it is possible to base economic analysis of industrial process on assumptions based on the technical relationships involved rather than the economic environment. Writing in 1974, Marsden, et al, described this philosophy underlying this approach:[15]

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14. James Marsden, David Pingry and Andrew Whinston, "Production Function Theory and the Optimal Design of Waste Treatment Facilities," Applied Economics, vol. 4 (1972), pp. 279-290.

15. James Marsden, D. Pingry and A. Whinston, "Engineering Foundations of Production Functions," Journal of Economic Theory, vol. 9 (1974), p. 127.

> What we wish to do is break from (the standard) approach and, viewing the production function as a technical relationship representing the 'maximal output achievable from a given set of inputs,' proffer an alternative derivation method based on the general reaction principles of many processes. The primatives are this shifted from the economic properties to the engineering relationships used. The validity of the final production functional form rests on the accuracy of the engineering relationships used rather than on the preciseness of the economic properties assumed.

When this approach has been adopted, the engineering variables were known _a priori_ (e.g., temperature, pressure, volume in the case of steam), as was the general functional form of Eq. 1.1. The situation is somewhat different in the present study, but the processes are susceptable to the same type of analysis. Not all of the variables and functional form of the engineering relationships are known. Moreover, it is believed that Eqs. 1.1 and 1.6 change as functions of both time and cumulative production. Here, the direct effect of reservoir depth, for example, on the capital requirement is to be determined. However, the derivatives g_1' and h_i' from Eqs. 1.4 and 1.6 are viewed as impact multipliers, giving the marginal effect on product or cost of a unit change in an engineering characteristic -- whether v_1 is steam pressure or reservoir depth.

Because the precise forms of the constraints posed by physical and chemical laws are not known in this case, the approach developed by Chenery, Smith and Marsden, et al, will be modified. The equations of Chenery will be rewritten such that product, X, is specified not just in v_1 or alternatively u_1, but a combination of both:

$$X = j(V,U) \tag{1.7}$$

where,

V = $(n \times 1)$ vector of v_i, engineering and geologic characteristics of a field.

$U = (m \times 1)$ vector of u_i, purchased inputs for the field.

Therefore, Eq. 1.6 can be rewritten as,

$$C = k(V,U) \tag{1.8}$$

The changes in Eqs. 1.7 and 1.8 over cumulative production from a field or basin and over time will be empirically examined. Any systematic variation of the production and cost functions arising from depletion or time will contribute to their value in signalling scarcity. As mentioned on page 9, it is felt both that changes in the values of the elements of V are largely determinant functions of depletion and that sufficient data exists to determine (at least bound) their future paths. The time path of cost can then be found by estimating Eq. 1.7 or 1.8 and substituting values of V (determined by depletion) and solving for either production at a level of cost, or vice versa. Both will describe a supply function.

If Eq. 1.7 and 1.8 do fully specify the production of crude oil (or another mineral), then it is at least possible that economic models of production based on the standard form of

$$X = m(U) \tag{1.9}$$

are misspecified and their results would be inefficient, and perhaps positively or negatively biased.[16] In their comparison of geologic and economic models of the petroleum discovery process, Drew, Attanasi and Root concluded that the

16. Jan Kmenta, <u>Elements of Econometrics</u>, (New York: MacMillan Publishing Co., Inc., 1971), pp. 392-395.

inclusion of physical variables was important to correctly estimate the quantities discovered per unit of exploratory effort in a basin.[17] Additionally, they said that changing characteristics (V) of the newly discovered fields (they mentioned size) would influence both cost of production and ultimate recovery. These relationships might not be captured by models omitting physical parameters. This empirical proposition can be addressed if it is found that V is a relevant variable in Eqs. 1.7 and 1.8, and therefore the source of possible inefficiency and bias where it is omitted.

Plan of Research

The body of this dissertation includes full specification of the functions which are generally expressed by Eqs. 1.7 and 1.8, description of the data and statistical methods used to estimate the relationships, presentation and discussion of results. Specifically, the remaining chapters will be organized as follows.

In Chapter 2, the cost functions to be used in the study will be derived. This will include explanation of the postulated relationships between purchased inputs, and the objectives of producers. The engineering and geologic characteristics of the fields thought appropriate for inclusion in V will be described along with a priori expectations on their role in production.

In Chapter 3, the determination of cost will be explained. The data on cost, production and the geologic and engineering variables will also be reviewed. Limitations on the study imposed by the availability of data or required manipulations will be listed.

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17. Drew, Attanasi and Root, op cit.

In Chapter 4, the techniques for determining the elements of V, estimation of the cost functions, and analysis of the variation in cost over time are outlined. The results of estimations of field and basin cost functions will also be presented. This consists of the partial derivatives from the functions based on Eq. 1.8 and the statistical significance of the estimates.

In Chapter 5, the results are analyzed for the information they may contain about the economics of crude oil production. This approach to unit cost analysis is also reviewed with respect to the criticisms of its use as an indicator of scarcity. Finally, the value of the engineering production function in the case of crude petroleum production is assessed.

Chapter 2

Elaboration of the Model

In this chapter, the functional form of the cost functions are developed, including the elements of vectors U and V from Eqs 1.7 and 1.8. In order to produce estimable functions from those equations, two types of assumptions are imposed. The first of these relates to the producer's objective function and how decisions are made at the field level. The second concerns the technical relationship among purchased inputs. These two sets of assumptions are explained in the first two sections of the chapter. In the third section, the engineering and geologic characteristics of the field expected to influence cost will be introduced. For those elements of V that have already been investigated, the information on their influence is given. In other cases, the choice of variables and expectations on their role in the model will be guided by general principles of geology and petroleum engineering.

The Objective Function of Producers

The type of optimization usually employed in a study such as this assumes that a price-taking firm chooses the level of output and the combination of inputs to maximize profit. Though individual producers of oil are undoubtedly driven by profit, this objective function would not be the best to capture production from a single field. Typically, there are many producers of a single field. Because petroleum in any field is fungible and finite, an important externality attends the production decisions of individual firms in the field. It is that the rate and quantity of production by one firm can directly affect the current and future costs and production possibilities of other firms in the field. This includes the ultimate recovery from the field by all firms.

To minimize potential physical waste of a finite resource in which there is a social interest and to support economic objectives, government bodies have regulated production decisions. As early as 1907, state regulation began in Oklahoma to prevent the physical waste of oil. Other producing states followed suit over the next twenty years, relying principally on the goal of conservation. The objective of some state and federal regulators broadened during the Depression to include market considerations. Between the 1930s and the end of World War II, the role of the federal government, the Interstate Oil Compact Commission and state regulators became pervasive in production decisions.[18]

The extent and rationale of regulation varied by locality. Soladay divided the eighteen states which produced 97% of domestic supply from 1948-1974 into three groups based on the nature of regulation.[19] For the first group of states (Texas, Louisiana, New Mexico, Oklahoma and Kansas), field proration orders were set to meet projected market demand. For the second group (Arkansas, California, Colorado, Mississippi, Montana, Nebraska and Wyoming), production was limited by the the engineering concept, "maximum efficient rate" (MER) of production.[20]

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18. For economic analysis of state and federal regulation of petroleum and natural gas production, see James W. McKie and Stephen L. McDonald, "Petroleum Conservation in Theory and Practice," Quarterly Journal of Economics, vol. 76 (1962), pp. 98-120 and Wallace F. Lovejoy and Paul T. Homan, Economic Aspects of Oil Conservation Regulation (Baltimore: Johns Hopkins University Press for Resources for the Future, 1967).

19. John J. Soladay, "Monopoly and Crude Oil Extraction," American Economic Review, vol. 69 (March, 1979), pp. 234-239.

20. Soladay, p. 235 defines MER as the rate "essentially designed to maximize the undiscounted stream of current and future oil recovery from reserves." B.C. Craft and M.F. Hawkins, Applied Petroleum Reservoir Engineering (Englewood Cliffs, NJ: Prentice Hall, Inc., 1959), p. 197, define MER as the rate of production "above which there will be a significant reduction in the practical ultimate oil recovery."

For the third group, (Illinois, Indiana, Ohio, Pennsylvania, Kentucky and West Virginia), there was no state regulation. It should be noted that the joint contribution of the last group to total production is very small, and that most of the important producing states are in the first group.

Because of the widespread acceptance in the industry of exploiting reservoirs as single units, even for the small share of production not covered by state regulations, an annual production constraint will be assumed for producers of all fields.[21] Regulation also covered spacing of wells, production rates and supervision of pressure maintenance, and recovery enhancement techniques. The joint effect of mandated and voluntary production practices was that production goals were established, for which cost would be minimized.

This is the basis for a constrained cost minimization as the objective function for this study. Its expression in an equation such as 1.8 can be developed based on a Cobb-Douglas production function. In the case of a cost minimizing objective, the following Lagrangian would be minimized:

$$J = wL + rK + z(X - VK^{a}L^{b}) \tag{2.1}$$

where,

J = Lagrangian form of the objective function.

w = wage rate.

L = labor input.

r = cost of capital.

K = capital input.

z = Lagrangian multiplier.

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21. Lovejoy and Homan, p. 63.

X = exogenously determined level of production.

$V = v_1^{f1} \cdot v_2^{f2} \cdot \ldots \cdot v_m^{fm}$, the vector of physical field characteristics.

a and b are constants to be determined.

This equation will be modified in the next section, so the mechanics of optimization and derivation of estimable functions will not be performed at this point.

For fields from which no natural gas is produced, Eq. 2.1 captures the relevant variables involved in the production process at the field level. However, in most cases, gas is present and is either produced for sale and may be used as an input in production to enhance either the rate or ultimate production of oil. If production decisions were made to maximize the joint production of oil and gas, the objective function would have to be changed.

Between 1950 and 1975, the share of U.S. net gas production coming from oil wells fell from one quarter to one seventh.[22] Of the gas produced from oil wells, almost one quarter was used in repressurization in 1975, down from nearly one half in 1950. With the oil field contribution to total gas supply so small, it is appropriate to treat gas revenues as incidental to oil production strategies. However, the presence and abundance of gas may be an important member of the V vector, which is examined below.

Because revenue does accrue and must be accounted for where gas is produced and marketed from a field, a modification can be made in Eq. 2.1 for this case. On the basis the role of gas in the production process, all fields will be divided into three categories:

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22. American Gas Association, Historical Statistics of the Gas Utility Industry 1966-1975, (Arlington, VA: American Gas Association, 1975), p. 11.

1. Those fields from which the principal product is gas, (i.e., where over 50% of the estimated ultimate hydrocarbon recovery was natural gas). These fields will be omitted from the study.

2. Those fields from which only oil is marketed. The model for these fields is based on Eq. 2.1.

3. Those fields from which both gas and oil are produced and marketed. In these cases, the revenue from gas sales will be treated as a subsidy to the cost of producing oil. Equation 2.1 will be modified in this case to become:

$$(2.2) \qquad (C - (P_g G)) = wL + rK + z(X' - VK^a L^b)$$

where,

P_g = price of natural gas.

G = quantity of gas produced.

X' = quantity of gas plus oil produced.

Because of the small importance of associated gas in oil production decisions over the period under study, this treatment is more accurate than employing an objective function for joint production. For some producers, however, a comparison must be made between the value of marginal product of a unit of gas injected into the reservoir and the marginal revenue derived from its sale, which may complicate the model as it has been developed so far.

Equations 2.1 and 2.2 embody the assumptions about the objective functions of the fields' producers. As mentioned in Chapter 1 (pp. 11 - 12), cost minimization was the framework assumed by Marsden, et al, in their development of engineering production functions. In the case of the crude production industry, there is regulatory history to support this assumption. This complements Marsden's empirical observation that production strategy decisions at the plant level are best represented by cost minimization.

The Technical Relationship Between Labor and Capital

The form of the objective functions in Eqs. 2.1 and 2.2 is based on a Cobb-Douglas production function. Since the technology permits little or no factor substitution, Eq. 2.1 can be simplified to one input only, capital.

The implication of this assumption is that capital and labor are employed in fixed proportions in the petroleum extraction process. This does not require that the ratio of labor to capital remain constant over time. Within any given year, though, no possibilities of labor/capital substitution exist. This fixed factor demand arises from the nature of drilling and production operations. Because it is unlike other mining processes, the technology of making a 15 inch hole in the ground inherently allows less labor/capital substitution than digging shafts and tunnels or scooping out the surface of the earth. Once a drilling rig is fully manned, additional labor input cannot be employed as a substitute for any of the drill pipe, bits or any other part of the integrated capital investment in that well.

In the crude oil and gas well drilling industry, the ratio of total wages to capital expenditures remained around 45% between 1954 and 1972.[23] During the same period, the ratio of total wages to the total value of shipments declined from 12% in the 1950s to 6.7% by 1972. These trends suggest that, in the absence of a strong shift in relative prices, the relationship between labor and capital is fairly stable over time, as well as at a given point. The small and declining role of labor in the cost structure is also clear. Any variation

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23. U.S. Department of Commerce, Bureau of the Census, 1977 Census of the Mineral Industries, Subject, Industry and Area Statistics, (Washington, D.C.: Government Printing Office, 1979), p. 13C-5.

in labor demand between fields, arising from the vector V, is hard to imagine.

If there were ready opportunity for labor/capital substitution it would require some change in the engineering production function approach. However, Marsden, et al, recommended that,[24]

> . . . in the more highly technical processes, which are becoming more and more prevalent, where labor does not enter as a substitutable input, the engineering formulation is directly applicable. Indeed, we argue that this approach is preferable since it provides a basis for important direct technical analysis.

Adopting the simplification of fixed proportions, in addition to a better approximation to reality, permits greater attention to be focused on the technical cost/deposit quality relationship. Additionally, zero elasticity of substitution between the inputs obviates the need to allocate costs between them. This provision is also necessary as there are no data that allow the identification of differences in the labor input between fields, as there are in the case of capital. On this basis, Eq. 2.1 will be modified as follows:

From the assumption of zero elasticity of substitution, labor is a constant proportion of capital, or $L=sK$. Then the production function in Eq. 2.1 becomes,

$$(2.3) \qquad X = VK^{a}(sK)^{b}$$

Simplifying,

$$(2.4) \qquad X = VK^{a+b}s^{b}$$

As there is now only one choice variable left in the problem, the constraint in the objective function represented by Eq. 2.1 can be substituted out. From Eq. 2.4, capital may be expressed as,

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24. Marsden, et al, p. 137.

$$K = (X/Vs^b)^h \tag{2.5}$$

where,

$h = (1/a+b)$

Then this expression for capital can be employed in a capital intensive cost function,

$$C = r(X/Vs^b)^h \tag{2.6}$$

This expresses cost as a function of the vector of exogenous physical characteristics of the field, (V); the exogenously set level of production, (X); and an exogenously set cost of capital (r), and the exogenous labor/capital ratio (s). Taking the natural logs of both sides of Eq. 2.6, where there are two elements in the vector V, a linear, estimable cost function may be derived:

$$\ln(C) = \ln(r) + h(\ln(X)) - hf_1(\ln(v_1)) - hf_2(\ln(v_2)) - h(\ln(s^b)) \tag{2.7}$$

Which can be simplified to,

$$\ln(C) = \ln(r) + h(\ln(X)) - hf_1(\ln(v_1)) - hf_2(\ln(v_2)) - hb(\ln(s)) \tag{2.8}$$

For the case of fields in which gas is produced and marketed, Eq. 2.2 would be modified to,

$$\ln(C - (P_g G)) = \ln(r) + h(\ln(X)) - hf_1(\ln(v_1)) - hf_2(\ln(v_2)) - hb(\ln(s)) \tag{2.9}$$

Eq 2.8, and its modification for the case of associated gas, represent both the cost minimizing objective function and the zero elasticity of substitution production function. These form the bases for estimable functions which will be used in this study.

Physical Parameters in the Model

A motivating force in employing the engineering production function in modeling economic processes is exploitation of the information available from relevant physical and chemical laws. Here, definition of the role of those relationships in the production of crude oil is a fundamental objective. The analysis will be conducted through determination of the elements of V and their functional relationship to cost. There is already some information on the elements of the V from previous research. For others, however, their choice and expectations on their role in production is based on general principles of geology or reservoir engineering. In this section, a priori expectations on the elements of V and their functional relationship to cost will be explained. In all instances, the relationships posited below are hypotheses, the validity of which will be tested in the course of the research.

There appear to be four principal routes through which physical factors, V, influence the cost of production:

1. Factors which influence the cost of drilling each well.

2. Factors which determine the number of wells required to exhaust the field.

3. Factors which influence production costs beyond drilling.

4. Factors which influence the marginal cost of production from secondary or tertiary recovery methods.

This research is limited principally to the influence of the elements of V on cost, acting through the first two routes. Some of the elements of V may affect cost through more than one route. Each of the factors expected to impact cost will be covered according to its principal means of influencing cost.

DRILLING COSTS

The cost of drilling and completing production and dry wells comprises the major portion of the cost of production at the wellhead. There are a number of parameters which can influence the cost of drilling, the most important of which is depth. Though the importance of drilling in total cost diminishes as more intensive recovery efforts are applied to a field, now and for the foreseeable future, drilling cost will dominate. The following physical factors have been associated with impacts on the cost of drilling.

Reservoir depth is unquestionably the most important variable in the cost of drilling. Inputs to drilling can be divided into two classes based on the influence of depth on their demand. For the first class of inputs, demand rises linearly with depth. This includes casing, drill pipe, drilling mud and other items consumed roughly on a per foot basis. For the second class of inputs, demand rises exponentially with depth. This includes energy, rig time and perhaps drill bits. The demand for inputs of the second class overwhelms those of the first to yield a long observed exponential relationship between the cost and depth of a well.

There are several reasons for the rate of escalation of costs with depth:

1. The rock at the surface is usually far less indurated then rock of the same lithology at greater depth. The harder the rock, the more time, materials and energy it takes to penetrate it.

2. Because the temperature and pressure in rock bodies increase with depth, special equipment is often required for drilling and completing wells in a high pressure/temperature environments. These conditions can cause drilling to slow, an increase in down-time or both.

3. The capacity of a drilling rig is measured by the depth it can drill. These capacities do not change in a continuous fashion,

but in a step function. The same applies to many of the well services.

Some of the differential is based on the marginal cost of rendering the same service in wells of different depths. Some of it, however, is probably due to the differences in elasticities of demand for well services as depth changes. For example, electric log and other formation evaluation services are bought to reduce uncertainty surrounding the decision to complete the well once the hole is drilled. The cost of completion increases with depth, so as the amount at risk rises, the amount paid to insure against the loss rises as well. Formation evaluation firms have, thereby captured some of the pure rent to the information they generate, for instance, by doubling the charge per foot for wells over 15,000'.

The relationship between drilling cost and depth is expected to be generally the same across fields in the same basin, but variable across basins.

<u>Geologic and geographical setting</u> can substantially change average costs between otherwise similar wells. The reasons relate to either the economic geography of the field location, or the regional geology. Differences in cost stemming from the former are principally related to transportation costs. While it is intuitively easy to see why wells drilled offshore, or on the Alaskan North Slope are more expensive; locational influences need not be so profound. Just because of the absence of a local, established industry infrastructure, frontier areas may have higher average costs.

Drilling costs can also differ over areas because of the nature of the rock between the surface and the reservoir. Particularly hard formations, such as those in Permian Basin of West Texas, can add to drilling cost through increased energy requirements, greater bit failure, and increased down-time associated with changing bits. On the other hand, hard, mechanically competent rocks do not fall into the well bore as readily, obviating the need for some of the steel casing. In the Gulf Basin, where the rocks are soft and incompetent even at substantial depths, the wells are lined throughout their depth with casing, to prevent caving.

Type of completion refers to whether oil, gas or both is produced from a single well. The cost of completing the well is traditionally reported as a part of drilling cost. Additionally, the cost of completion changes at a differential rate with depth between oil and gas completions.

NUMBER OF WELLS

The total drilling costs associated with development of a field are governed by the average cost of a well and the number of wells required to produce the field. Therefore, the number of wells: productive or dry, that are drilled strongly influences the average cost of production. There are two main routes through which differences in the number of wells per geologic unit of production can arise. First is through the drilling success ratio (ratio of number of successful wells to the total number drilled). A well can be unsuccessful because either the drilling target did not contain the anticipated hydrocarbons, or because some accident forced abandonment of the hole before completion. The second reason relates to the average volume of reservoir rock drained by each well. Differences in well productivity between fields arise from the geologic characteristics of reservoir, physical attributes of the liquids and gases and level of energy in the reservoir.

Depth may increase the number of dry wells in a field because it is harder to hit a target of given size the further away it is. This problem is compounded by the fact that geologic and geophysical information on the target itself deteriorates with increasing depth, in a discontinuous, perhaps even exponential fashion.

Depth can also contribute to the likelihood of accidents forcing the abandonment of a hole. This risk is not simply linear in depth, but increases faster at great depths because of the danger of accidents resulting from high pressure environments. Depth is not expected, in itself, to influence the effective area of a well. However, due to the correlation of reservoir pressure and depth, effective areas may be larger in deep fields, reducing the number of wells required.

Field size in the first instance may evoke general economies of scale. Secondly, it determines the size of the driller's target, hence probability of success. Thirdly, the ratio of field area to field perimeter grows with increasing size. As the likelihood of a dry hole on the edge of a field is greater than in the center, ceteris paribus, the larger the field, the fewer dry holes per unit of ultimate recovery.

Economies of scale in the physical size of a field have been demonstrated by Arps and Roberts. They found in the case of the Denver-Julesburg Basin, that ultimate recovery from a field was proportional to field area, to the 1.275 power. The number of dry holes was proportional to field area to the 0.345 power, therefore the increase in efficiency and decrease in drilling failures generated the savings. This arose not only from the relationship of perimeter size to area, but because:[25]

> the larger fields will generally have a thicker oil column, and, in the case of stratigraphic traps, because of their sizes, will usually extend further from the pinch-out line, thus generally having less shaly, but a better developed section.

Attanasi and Drew have taken the analysis of differential risk at the periphery and center a step further to demonstrate that it influences the competitive environment of firms operating in those areas of the same field.[26]

Trap type refers to the geologic mechanism by which hydrocarbons are confined to a certain body of rock, or part of a rock body. Traps are classified generally into structural, stratigraphic or combination, diagrams of which are shown in Figures 2.1.a through 2.1.l.[27] Structural traps usually rely on faulting, folding or both of the reservoir-seal complex to provide the required closure and permeability barrier. Structural traps also include instances where hydrocarbons are trapped by the juxtaposition of the reservoir to a body of salt, or crystalline rock (which are impermeable), as illustrated in Figures 2.1.d and 2.1.e. Stratigraphic traps form due to a change in the permeability of rocks within a unit (other than when associated with faulting). Combination traps encompass elements of both. Structural

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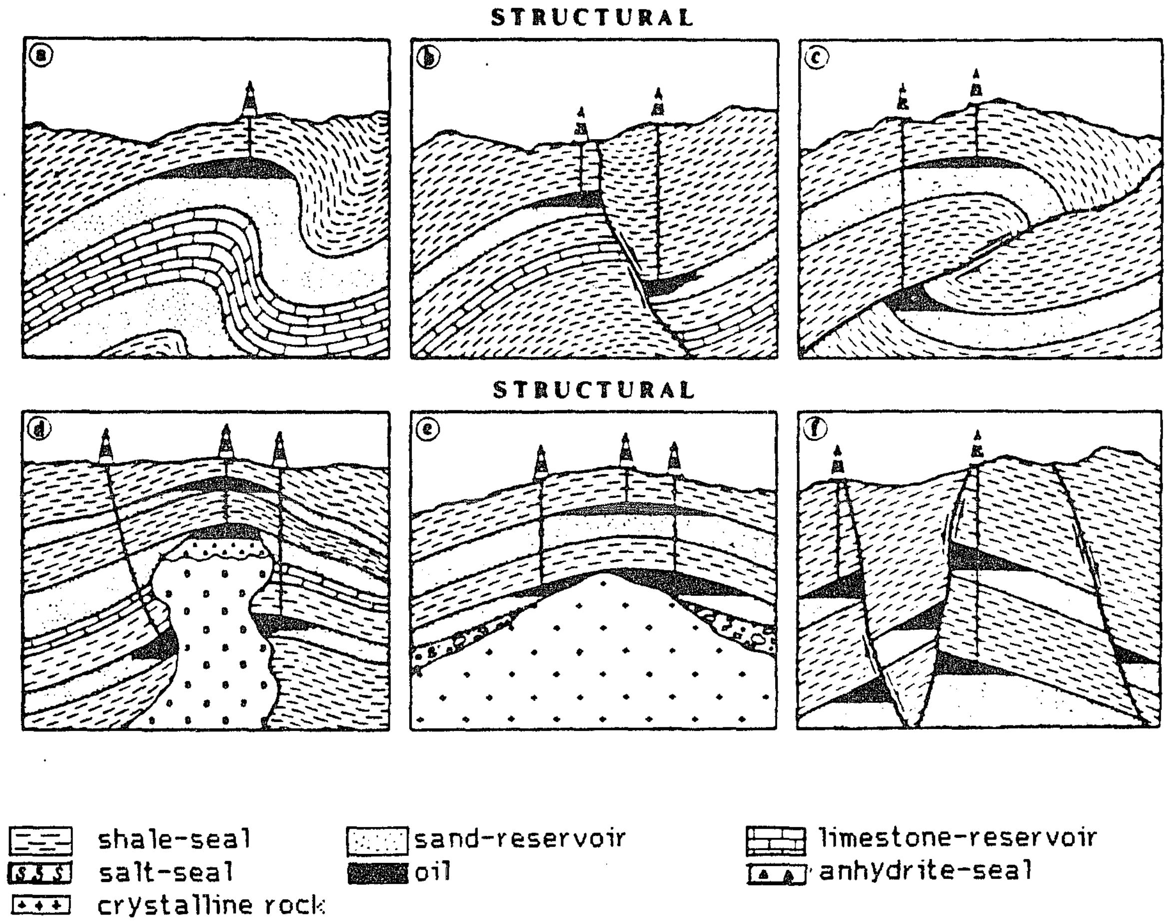
25. Arps and Roberts, p. 2558.

26. E.D. Attanasi and L.J. Drew, "Market Structure and Firm Performance in Oil and Gas Exploration," Unpublished manuscript, 1981.

27. L.W. LeRoy, D.O. LeRoy and J.W. Raese (eds), Subsurface Geology, Petroleum, Mining and Construction, 4th ed., (Golden, CO: Colorado School of Mines, 1977), p. 242.

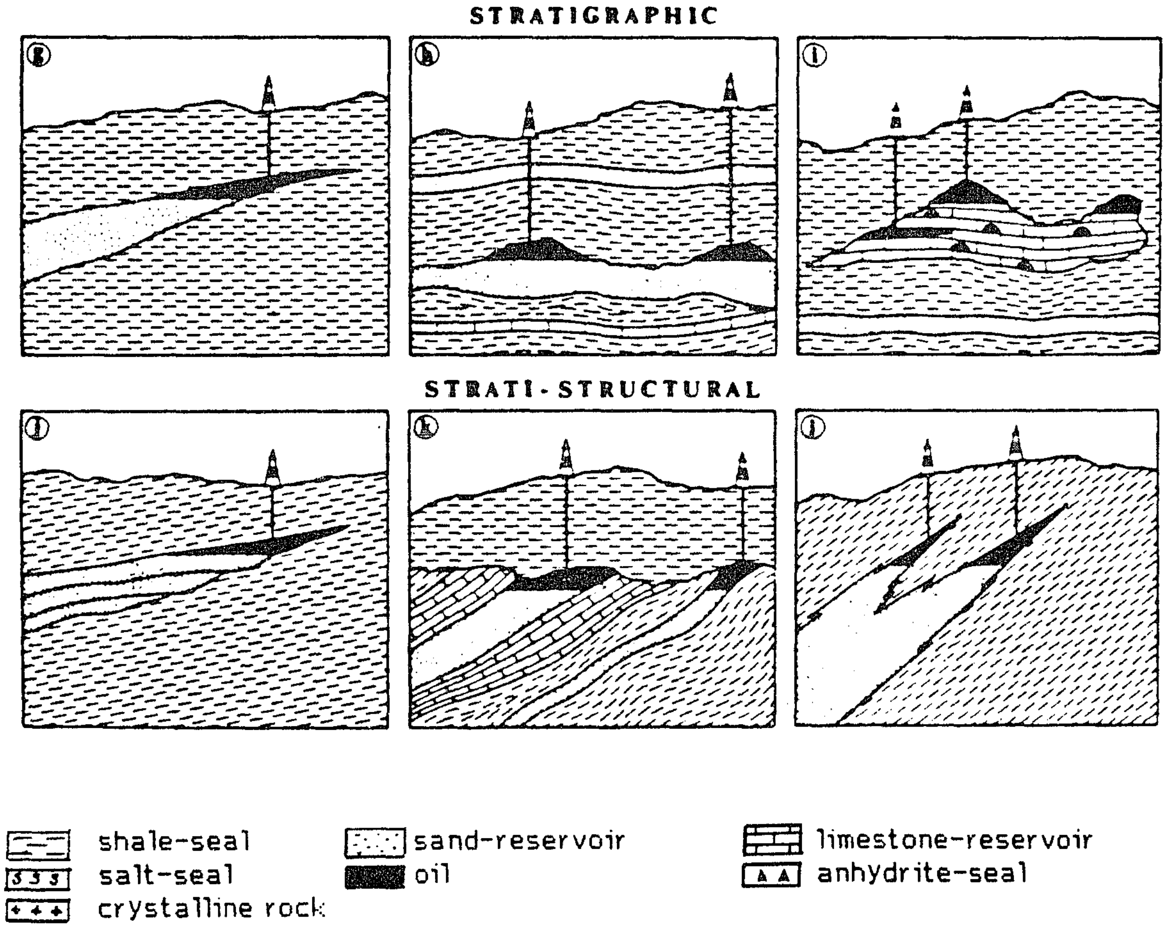
Figures 2.1a - 2.1f



The structural traps in Figs. 2.1a - 2.1c rely on folding for the trapping mechanism. Fig. 2.1a represents a fold, in which the oil has concentrated at the crest of the permeable sand. Figs. 2.1b and 2.1c both represent faulted structures, where the barrier to flow is created when an impermeable shale is thrown into contact with the sand reservoir by faulting action. Fig. 2.1b represents normal faulting, which is common in the Gulf Coast Basin, and Fig. 2.1c represents reverse or thrust faulting, which is common in the intermontaine basins of the Rockies.

Fig. 2.1d shows a typical field associated with a salt dome. These are common in the Gulf Coast Basin. Fig. 2.1e shows a regional uplift (anticlinal fold) created either through the pre- or post-depositional emplacement of a large crystalline rock body. The oil gathers at the crests of the domed structures created by the folding. Fig. 2.1 shows substantial block faulting, as occurs in the Coastal Basins of California.

Figures 2.1g - 2.1l



Figs. 2.1g and 2.1h represent stratigraphic traps which arise out of an unconformable surface between the sand and shale bodies. The oil has risen to the highest point in the body, where it encounters the change in lithology to impermeable shale. Fig. 2.1i represents a reef structure, which is a common setting for carbonate (limestone) reservoirs.

Figs. 2.1j through 2.1l represent combinations. In all three cases, the trapping mechanism is a permeability barrier due to a lithology change. The structural aspects of the traps arise mainly from the substantial dip of the beds, particularly in Fig. 2.1k.

traps represent more radical breaks in the geologic environment of the subsurface. As a result, they are easier to locate and define by standard geologic and geophysical techniques. Because of the subtlety of their permeability barriers, stratigraphic traps are likely to be deliniated only after a greater number of wells, on the average. No a priori expectations are held on the influence combination traps might have on the production process. It is assumed that they will have the influence of the major trap type to which it is most similar.

Thickness and geometry of productive interval influences the shape of the driller's target and, as mentioned by Arps and Roberts, economies of scale in production. If the field is composed of vertically stacked productive horizons, the possibility exists for producing them successively through the same well. (These are usually produced from the bottom up). If the field is areally extensive, but has thin reservoirs, or if they are stacked in such a way that prohibits intersection by a single well, more wells would be required than in the vertically stacked case.

Effective permeability of a reservoir measures the ease with which gases and liquids flow through the reservoir rock. The concept of permeabilty is based on Darcy's Law, generally stated as:[28]

(2.10) $$v = -(k/u)(dp/ds)$$

where,

v = the rate of liquid or gas flow in $cm.^3/sec.$ across a given area of rock.

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28. Craft and Hawkins, p. 259.

k = a proportional constant, the permeability of the rock.

u = the viscosity of the liquid or gas flowing through the rock, in centipoise.

dp/ds = the pressure gradiant taken over the same direction as the flow, measured in atmospheres per $cm.^2$.

This involves three important physical parameters: fluid and gas viscosity, pressure and rock permeability. Fluid and gas viscosity are given in a reservoir. The higher the viscosity, the slower the flow or the shorter the transport under a given level of pressure. Therefore, investment in greater drilling density or pressure maintenance is assumed to be an increasing function of viscosity. Viscous oil is a main target of EOR techniques.

Formation pressure is maintained either by the natural drive process which generates pressure on the hydrocarbons, or through the actions by the operators to generate more pressure than is naturally present. The source of the natural energy in the reservoir is covered in discussion of the drive mechanism, below.

The inherent permeability of the rock is related to the physical characteristics of the channels through which liquids and gases flow, and the chemical characteristics of the rock walls of those channels. The type of channels available as pathways in the rock is usually determined by the porosity type. Its role will be discussed under porosity and porosity type, below. The chemical reactions between the fluids and gases and the rock itself is a function of formation lithology, and will be covered in that section.

Drive mechanism refers to the sources of the pressure which move the hydrocarbons to and up the well bore to the surface. This pressure can be generated by the effect of gas expansion - - either gas dissolved in the oil, or free in a gas cap above the oil, or expansion of the liquid itself. In either event, the expansion pushes the liquid toward the point of least pressure, which is at the well. Pressure may also be generated by the upward migration of formation waters trapped under the oil layer in the rock. As oil is produced from the top, the water moves up under it, maintaining the flow of oil toward the well. Pressure can also be generated by the force of gravity.

The efficiency of these mechanisms is measured by the quantity of oil that is produced from a unit reduction in reservoir pressure. Both water and gas drives, depending on their longevity are very effective mechanisms of primary oil production from a field. The ultimate contribution of the drive mechanism can be measured by the quantity of original hydrocarbons in place produced before pressure maintenance was required.[29]

Formation lithology may affect the permeability and therefore the effective area of wells. Of the two principal types of reservoir lithology: sandstone and carbonate, the latter is more chemically reactive than the former. Movement of fluids and gases through the pores causes changes in the chemical equilibrium which may raise the quantity of energy required to move the hydrocarbons toward the well bore. Because some enhanced oil

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29. R.C. Craze and S.E. Buckley, "A Factual Analysis of the Effect of Well Spacing on Oil Recovery," Drilling and Production Practice, 1945, (New York: American Petroleum Institute, 1946) discussed the influence of drive mechanism, reservoir lithology and other elements of V on residual oil saturation after the field was shut down. This is an indirect measurement of production efficiency, but not useful in structural analysis of the cost of production.

recovery (EOR) techniques rely on changing the chemical reactions at the fluid-rock boundary in the pores, lithology can constrain the choice of EOR techniques for application to a given field.

Effective Porosity and porosity type refer to the volume of void space in the rock, its geometry and the nature of interstitial connection. Porosity is the volume of void space in a rock divided by the volume of the rock, yielding a percent. Effective porosity reduces that number by the percent of void space occupied by substances other than oil or gas (usually water). The voids in the rock are the areas occupied by hydrocarbons, so the volume of hydrocarbons per volume of rock is directly dependent on porosity. The greater the concentration of oil per volume of rock, the greater the recovery from a well.

Intergranular porosity is the type that would be present in a box of wet sand, communication between the pores is usually very good. Vuggy porosity, is the result of small cavities being dissolved by the action of pore fluids, later replaced by oil and gas. Because these voids were formed in sometimes isolated microenvironments, connection between them is often poor. Fracture porosity occurs mainly in very brittle rocks, often shale (in the relatively rare instance where it is a reservoir rather than a seal). In this case the hydrocarbons occupy only the fracture openings in what is otherwise an impermeable rock. Depending on the size and geometric orientation of the fractures, the effective area of a well may be limited to the very small radius through which it is directly connected by fractures. Therefore, it is felt that porosity type may greatly influence the number of wells required in wells required in the field, and impact the possibilities for recovery enhancement after primary production is over.

POST-COMPLETION COSTS

After the wells are completed, costs are incurred in the maintenance of production equipment. Though this is usually the smallest component of average production cost, there are some physical characteristics of the fields which may influence post-completion production costs. Post-completion costs arise generally in one of two ways.

1. They are associated with pressure maintenance. The need for this operation is dictated by the efficiency of the natural drive mechanism in mobilizing the hydrocarbons toward the well bore and then to the surface. Factors which adversely effect the fraction of OIP produced under primary recovery will generate demand for pressure maintenance.

2. They are associated with preliminary treatment of the product stream. These requirements relate to the physical and chemical characteristics of the liquids and gases produced at the wellhead.

Liquids and gases must be separated before transport. Oil and condensates must be separated from water and other liquids, natural gas must be dried and certain impurities, particularly hydrogen sulfide (H_2S), must be removed. Therefore the surface production equipment requirements are almost fully determined by field characteristics - - no need for a gas-liquid separator if there is no associated gas, no demand for "sweetening" equipment if there is no H_2S.

ENHANCED RECOVERY COSTS

Production of a well under the natural pressure of the reservoir is called primary recovery. About 25% - 30% of OIP is recovered from an average field under primary recovery. Secondary recovery usually refers to techniques for enhancing flow rate or recovery by gas injection or water flood. The aim of the first method is to reduce the viscosity of the liquid in the well, hence reducing the pressure required to push it to the surface. Gas can also be injected to maintain reservoir pressure. The second method is to generate, or stimulate a water drive in the reservoir. Pumping the oil from the surface also falls into the class of secondary recovery techniques. Secondary techniques can raise ultimate recovery to 30% to 35% or more.

Tertiary, or enhanced oil recovery (EOR) techniques refer to largely experimental production strategies beyond pressure maintenance and pumping. Currently there is only a very small percentage of annual domestic production that comes from EOR. However, the efficiency of application of most of the EOR techniques is sensitive to the values of the physical variables employed in this study.

Currently the five leading EOR techniques are:[30]

1. In situ combustion. This involves lighting a fire at one end of a reservoir and forcing air into the wells to drive the fire toward recovery wells. Generally applied to highly viscous oils.

2. Steam injection. There are two variants to this method, cyclic steam injection ("huff and puff") and continuous injection.

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30. U.S. Congress, Office of Technology Assessment, Enhanced Oil Recovery Potential of the United States (Washington, D.C.: Government Printing Office, 1978), pp.26-31.

Both rely on the thermal action of the steam to mobilize viscous oil. Steam methods are the only EOR techniques with which there is substantial field experience.

3. CO_2 miscible flood. In this process, the oil is dissolved by the agent injected into the reservoir. The dissolved oil flows more easily than the more viscous that remained in the reservoir after primary and secondary recovery. Carbon dioxide is the most common miscible agent used in the U.S.

4. Surfactant/polymer flooding. This processes introduces chemicals into the reservoir which change the relationship of the oil to the rock surrounding it, increasing the effective permeability of the rock. The action of surfactants in a reservoir is the same as soapy water in an oily cloth.

5. Polymer-augmented waterflooding. This involves adding chemicals which change the relationship of the oil to the rock surrounding it, increasing the effective permeability of the rock. This increases the efficiency of the water in mobilizing the oil toward the wells.

Because serious consideration of these techniques is a product of the last twelve years, there has been substantial investigation of their feasibility and efficiency in raising the level of recovery from already discovered fields. The model developed by Lewin and Associates for the Office of Technological Assessment specifically analyzed the technical suitability of each of the techniques with respect a vector similar to V.

Chapter 3

Data on the Variables

Data on the variables in these models are of two types: economic data on costs and the capital investment in fields, and technical data on the geologic and engineering variables which enter the V vector. For the economic variables, not only must data sources be identified, but choices made on the treatment of capital depreciation and taxation of operations. These relationships have been simplified in order to concentrate on the role of the physical variables in production. For the technical data, the problems of preparation for estimation lie in the diversity of qualities they represent and incommensurability of their measures.

The chapter consists of three sections. The first reviews the general limitations imposed on time and regions by the availability of both economic and technical data. The second section presents the economic data, including measurements of total field production costs, and the stock and cost of capital. The third section explains how the technical parameters will be measured.

General Data Limitations

Both principal sets of data come from data bases developed by the Center for Energy Studies (CES) at Louisiana State University. They are the U.S. Oil and Gas Field Data Base and Drilling Cost Data Base.[31] The former

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31. Center for Energy Studies, Lousiana State University, Drilling Costs Data Base, User's Manual, (Baton Rouge: Louisiana State University, Center for Energy Studies, 1984) and Oil and Gas Field Data Base, User's Manual, (Baton Rouge: Louisiana State University, Center for Energy Studies, 1984).

contains data, by field, on the technical variables in a file called GEOL. In a separate file, called PROD, it contains annual records of drilling and production of oil and gas. The Drilling Cost Data Base has been used to assign costs to the wells recorded in the PROD file.

The Oil and Gas Field Data Base is a collection of about 22,000 reservoir records on approximately 3,200 separate oil and gas fields in the United States. These fields contain reserves of at least 10 million bbls. of oil equivalent.[32] The fields were originally identified, and data assembled by Richard Nehring for his study of trends in U.S. discoveries.[33] Though the Department of Energy currently lists 39,158 fields in the U.S., the distribution of resources with respect to field size is very negatively skewed. Most of the oil and gas, in a basin or larger region, is usually concentrated in a relatively small number of very large fields. The fields in the Nehring study, while comprising less than 10% of the population of U.S. fields, contained 92% of the oil discovered in the U.S. as of 1976 (outside the Appalachian region).

The fields identified by Nehring were chosen as the population for the study for four reasons:

1. Nehring's study established a standard for definition of the fields and represented the fraction of fields that is most important in domestic supply.

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32. Combination of the values of oil and gas in this size evaluation was made on the basis of the Btu. value of the two products. The ratio used was 6 MCF of gas to 1 bbl. of oil.

33. Richard Nehring, op. cit.

2. Generally, the availability of field data for academic study is proportional to field size. Because of regulation and recent federal interest in petroleum supply, large quantities of data have been gathered on the most important, largest fields.

3. The importance of the largest fields in regional supply is not unique to the U.S., but is observed world-wide. Because the center of this research is examination of the relationship between the physical environment of production and cost, the conclusions drawn would be more valuable in analyzing costs outside the U.S. if the group studied was composed of large fields, which are important in all petroliferous provinces.

4. Large deposits play a predominating role in many mineral industries. Analysis of economies of scale and ore "quality"/ quantity relationships could be compared to studies in metals, coal and other mineral resources.

Because of the standardized form of the Nehring data, and its broad coverage of the domestic petroleum resource base, extension and independent analysis of the findings here can be easily conducted. Additionally, as the data have been put in the public domain, problems associated with the use of proprietary data were eliminated. Although these data sets offered the best available support for this research, several problems arise with their use which impose limitations or modifications of the research design. Specifically, the geographical areas covered and the length of time series were directly imposed by the availability of data.

The fields from Texas and those offshore were eliminated because of insufficient quantity or quality of data in the data bases. For the fields used in this study, data on complete sets of technical variables were required, as well as complete production and drilling data. The drilling and production histories in the PROD file were made immediately available through a Department of Energy (DOE) study of production decline curves, which unfortunately did not include Texas. The loss of Texas from the population is obviously important, but insusceptible to correction without resort to very expensive private data bases. Therefore, of the 3,200 fields in the GEOL file, for the 1,500 fields on which drilling and production data are available (in the PROD file), all are outside Texas.

The elimination of the offshore fields was related to problems in the quality of data on drilling cost for offshore wells. The ultimate source for these data is the Joint Association Survey of Drilling Costs (JAS), managed by the American Petroleum Institute. Respondants to the JAS reporting offshore drilling appear to have misinterpreted instructions and allocated the costs in large drilling operations in a way that diminishes the value of the data for comparison with onshore operations.[34] The offshore is

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34. The problem has been reported by Ted Anderson of the DOE/EIA Field Office in Dallas and Richard Sparling, Director of Statistical Analysis for the Independent Petroleum Association of America, in Washington, D.C. (personal communications). It arises because drilling platforms often drill many wells from a single location in a program that may last for several years. Often, the program is divided into two distinct phases. During the first a rig drills a set of directional holes from the platform, each hole is evaluated and the rig drills the next hole. In the second phase, after initial drilling is complete, the productive holes are completed and dry wells properly plugged and abandoned. This type of operation created the situation where a single well would be drilled, then completed one or even two years later. Confusion arose on how to attribute the costs between years, as the JAS is not updated after its release. Because the procedures in estimating offshore costs varied between operators, the summary statistics may likely be biased below actual costs when drilling costs are rising, and above actual costs when they are falling. In any event, it seems inappropriate to use the data when comparing costs with onshore operations.

a very important part of the extensive margin in domestic oil production, and its omission circumscribes the forecasting value of the models developed here. However, many of the results derived in the present study should be directly applicable to the offshore, with an appropriate cost premium added. It is expected that the offshore environment produces a parallel upward translation of the cost curves, increasing average costs at all points, but not significantly affecting the marginal influence on cost of technical variables, depletion or time.

The second limitation imposed by the availability of drilling and production data is in time. Annual observations are available on drilling and production starting in 1942. Therefore, time series analysis must be restricted to fields which started production after 1940. The annual records on drilling end in 1972. As a consequence of these considerations, the study will be limited to 1942 to 1972, inclusive.

The third limitation was elimination of all fields which were predominantly gas. Fields were designated gas if over 50% of their estimated ultimate recovery (EUR) was constituted by natural gas.

Beyond the restrictions described above, statistical estimations of the models from Chapter 2 required a high degrees of data completeness on the technical variables. Of the original set of 1,500 fields in the PROD file, 156 fields were chosen for the study sample. These fields are listed in Appendix 1. The fields in the sample contain about 4.5% of the EUR of oil from all fields in the U.S. as of the mid-1970s.[35]

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35. U.S. Geological Survey, Geological Estimate of Undiscovered Recoverable Oil and Gas in the United States, U.S.G.S. Circ. 725 (Washington, D.C.: Government Printing Office, 1974).

Data on Economic Variables

In Chapter 2, the general form of the model to be estimated in the present study, Eq. 2.8, was derived. A variant was also developed to cover the case of the joint production of gas and oil, Eq. 2.9:

$$(2.8)\quad \ln(C) = \ln(r) + h(\ln(X)) - h(\ln(V)) - hb(\ln(s))$$

$$(2.9)\quad \ln(C-(P_g G)) = \ln(r) + h(\ln(X')) - h(\ln(V)) - hb(\ln(s))$$

Estimation of these relationships required data on total cost (C), the cost of capital (r), the labor/capital ratio (s), and for fields where oil and gas are joint products, the price of gas (P_g). The other variables involved in the equations are the product quantities: oil (X), gas (G) and oil and gas together (X') and the suite of technical variables (V). Data on total cost, cost of capital, the labor/capital ratio and the price of gas will be described in this section.

For estimation of the models based on Eqs. 2.8 and 2.9, annual total cost for the field, (C) was taken as the value of the service rendered by the net capital stock of the field in that year. The gross capital stock of the field in any year was taken as the total number of wells drilled in the field since initial production. Derivation of the value of services from the net stock is explained below. This definition of cost has two implications.

The first is that drilling wells is treated as an investment in the long run productive capacity of the field, rather than an operational expense, which contributes to production only in the year of drilling. In their analyses of production costs, both Bradley and Adelman treated drilling wells as additions to capital stock.[36] Bradley measured the contribution in terms of

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36. Paul Bradley, op. cit. and M.A. Adelman, The World Petroleum Market, (Baltimore: Resources for the Future/Johns Hopkins University Press, 1972).

addition to the productive capacity of the field, measured in bbls./day. Adelman analyzed the return to investment in drilling in the same discounted cash flow framework applied to many other capital projects.

The second implication is that this definition of C excludes production costs incurred in operations beyond the completion of individual wells. These include the costs of maintenance and field production equipment, and the costs of secondary and enhanced recovery techniques (EOR), all discussed in Chapter 2. The contribution of maintenance and production equipment to total cost is very small compared to the capital investment in wells, and determined principally by the number of wells.[37] These and the costs of secondary recovery and EOR can be treated additively in considering the influence of V on the total cost of production.

Determination of the annual observations on cost for a field was a two step process:

1. Computation of the annual value of the gross capital investment in the field.

2. Estimation of the value of service rendered by the net stock in each year of production.

The first step required calculation of the cost of all drilling in the field each year. These costs were based on data from the Joint Association Survey of Drilling Costs (JAS) in the <u>Drilling Cost Data Base</u>. These data are available from the 1950's by geographic region, depth

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37. Bradley and Adelman review the proportion of operating cost to total production cost and price.

and type of well (oil, gas and dry). For those years between 1942 and 1958 for which annual observations were not available from the JAS (1942-1952, 1954, 1957 and 1958), estimates were made. From 1948 through 1958, the estimates were based on the Drilling Cost Index of the Independent Petroleum Association of America, which is also in the Drilling Cost Data Base. The Index reports the annual average change in drilling cost from 1948-1983. The current dollar estimate of costs from 1942 through 1947 were set equal to the 1948 level, as no data on drilling costs were available prior to 1948. Because of war-time wage and price controls in place from 1942 to 1945, it was assumed that there were no significant changes in real drilling costs in that period. However, substantial inflation in 1946 and 1947 followed the removal of controls. To correct for this, and inflationary effects throughout the time series, all economic variables were adjusted by the GNP Implicit Price Deflator to a 1960 base.

The second part of the determination of C was computation of the value of the service rendered by the net capital stock each year. This figure was taken as equal to the amount by which the value of all wells in the field depreciated each year. Straight-line depreciation, based on an average useful life of 20 years for each well was employed to determine this figure. The average useful life was taken from the U.S. Internal Revenue Code of 1954 (IRS Code).[38] Using this formula, 5% of the initial investment in a well was imputed as the value of service for the year it was drilled, and 5% as the contribution for each of the following 19 years (after which the well was removed from the capital stock).

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38. Internal Revenue Code of 1954 (as amended), Section 167, Revenue Procedure 62-21 (Bulletin "F").

Included within this stock were productive and dry wells. Including dry wells is controversial. Under the IRS Code, the cost of dry holes is expensed in the year of drilling, rather than depreciated. However, the elimination of dry wells from the capital stock ignores the informational value of the dry holes, which is not limited to the year of drilling. Specifically, two "products" of dry holes continue to render a stream of services throughout the life of the field. First is the value of general geologic and engineering information on the field, which influences exploration and exploitation strategies. Second, every dry hole condemns a specific three dimensional volume of the driller's target. Therefore, uncertainty is reduced in subsequent drilling and production operations throughout the field. Adelman, defending the inclusion of dry hole costs in development investment concluded:[39]

> If an oil operator proposes to develop a known pool, he must face the odds that some development wells will be dry. Therefore, to consider only the costs of productive wells would be to underestimate substantially the number of wells and the expenses needed to develop the deposit.

Annual values for the cost of capital (r) were taken from the annual average yield on industrial bonds for those issues having a Moody's Aaa rating. This rate was believed to best represent both the opportunity cost of capital to the firm and approximately what the firm would have to pay to borrow the funds, or attract equity investment in production. The data on the labor/capital ratio were taken from the quadrennial Census of the Mineral Industries. Observations for years between each Census were determined by linear interpolation between the Census-year values. No data on the labor/capital ratio were available prior to the 1954 Census, so the 1954

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39. Adelman, op. cit., p. 56.

value of the ratio was used for all years prior to that year. For the price of natural gas (P_g), the average U.S. wellhead price, as reported by the Department of Energy, was used.[40]

The models based on Eqs. 2.8 and 2.9 did not incorporate the specific influence of federal or state taxes on crude production or the cost of capital. To the extent tax policy allowed spreading of costs between producing firms and taxpayers (as through depletion allowances and acceleration of depreciation), total cost is unaffected, though its incidence shifted. To the extent that taxation represented an addition to production cost (as through severence taxes), it usually was an increase in average cost, applicable to all producers without respect to V. Only after 1974 did legislation give preferential regulatory treatment to a share of domestic production based on field geology. Elimination of tax considerations allowed closer focusing on the role of physical variables in the model, without a significant effect on its approximation to reality in the pre-1974, cost-minimizing environment.

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40. Data on Moody's Aaa corporate bond yields, the GNP Implicit Price Deflator and the average wellhead price of natural gas for 1942-1970 come from the Bureau of the Census, U.S. Department of Commerce, Historical Statistics of the United States from Colonial Times to 1970, Bicentennial Edition, (Washington, D.C., Government Printing Office, 1976). Data on the GNP Implicit Price Deflator and Moody's Aaa corporate bond yields for 1971 and 1972 were taken from the Bureau of Economic Analysis, U.S. Department of Commerce, Current Business Conditions. Data on average wellhead price of natural gas for 1971 and 1972 were taken from the Energy Information Administration, U.S. Department of Energy, Natural Gas Annual, (Washington, D.C.: Government Printing Office, 1982). Data on the labor/capital ratio for the oil and natural gas drilling industry were taken from the Bureau of the Census, U.S. Department of Commerce, 1977 Census of the Mineral Industry, Subject, Industry and Area Statistics, (Washington, D.C.: Government Printing Office, 1979), table 13C-5.

Data on Technical Variables

In Chapter 2, the suite of geologic and engineering characteristics of oil fields was described and the rationale behind possible influences on cost discussed. In this section, the measurement of these variables is explained. Some variables are expressed in common units such as feet, acres or barrels; others though, represent less familiar quantities, such as darcies or degrees of API gravity. Because of the diversity of measures, a method of standardizing the observations on the variables has been adopted to test the sensitivity of the models to units of measure.

The variables in Eqs. 2.8 and 2.9 that require definition are the annual production variables: X and X' and the suite of technical parameters represented by the vector V. The annual observations on crude oil production for each field (X) was measured in standard 42 gal. barrels, gas production in thousands of standard cubic feet (MCF), measured at 14.7 psi and 60° F . The composite measure of oil and gas production (X') was computed by converting the gas to its average caloric equivalent to oil, 6 MCF of gas : 1 bbl. of oil, so the measurement of X' is in barrels of oil equivalent (BOE).

The suite of technical variables, V, available from the GEOL file of the <u>Oil and Gas Field Data Base</u> consisted of ten continuous and four discrete qualitative variables. Of the 14, all but one represent a physical dimension of the field. The last variable was the year the field was discovered, which was included to measure the influence of technical change over time. Because the purpose of this was to capture the degree to which capital stock vintage influenced cost, where a long period passed (greater than four years) between field discovery and initial production, the value of this variable was changed to the first year of reported drilling in the field. The nine continuous geologic variables, are described in Table 3.1.

Table 3.1

Measurement of Continuous Technical Variables

and Study Sample Means and Standard Deviations

Variable	Variable Name	Measure	Sample Mean	Std. Dev.
Estimated ultimate recovery	EUR	BOE $\times 10^6$	48.8	87.9
Depth	DEPTH	feet	6,733.1	3,268.9
Surface area	ACRES	acres	7,189.6	14,074.7
Number of reservoirs	POOLS	units	5.2	5.4
Average reservoir thickness	THIK	feet	47.3	63.1
Average reservoir porosity	POR	percent	17.2	6.1
Average reservoir permeability	PERM	millidarcies	224.0	439.4
Gas/oil ratio	GOR	standard cubic feet/bbl.	1,044.4	2,271.0
Oil gravity	APIGRV	degrees of API gravity	35.6	7.5

The two variables not measured in common units are permeability and gravity. Permeability was defined in Eq. 2.10. It refers to the absolute capacity of the reservoir rock to flow a homogeneous fluid of a specific viscosity at a given temperature and pressure gradient. The rate at which the oil in the actual reservoir flows to the well is also dependent on the viscosity of the oil, temperature and pressure gradient in that reservoir.

Because separate pressure and temperature data were unavailable, these variables were taken as direct functions of reservoir depth and are assumed to be captured within the DEPTH variable.

API gravity has been used as a measure of oil viscosity. Gravity and viscosity are not the same thing, but are functionally related in a nonlinear, inverse fashion for a given temperature and pressure. Therefore, low values of API gravity (in the teens or low twenties) represent oil which is highly viscous - it flows relatively slowly through rock of a given permeability with constant a temperature and pressure gradient.

In addition to the continuous variables, there are four qualitative variables which will be represented by a series of bivariate (dummy) variables. These variables are described in Table 3.2.

Table 3.2

Qualitative Variables

and Their Representation in the Sample

Variable	Variable States	% of Fields in Sample Having Characteristic
Lithology	Sand	60.8
	Carbonate or Mixed	39.2
Drive type	Fluid/gas expansion	60.3
	Gravity	18.5
	Water or Mixed	22.2
Trap type	Structural	48.0
	Stratigraphic or Mixed	52.0
Pore type	Intergranular	47.1
	Intercrystalline	15.0
	Other or Mixed	47.1

These reservoir qualities were described in Chapter 2. From these four qualitative variables and their ten possible states, six dummy variables were derived:

From Lithology	SAND = Sand
From Drive type	EXPNDRV = Liquid/gas expansion and
	GRAVDRV = Gravity drive
From Trap type	STRUC = Structural trap
From Pore type	GRANPOR = Intergranular and
	CRYSPOR = Intercrystalline

Part of this research is constituted by testing the feasibility of incorporating technical parameters in statistical models of economic processes. The seeming incommensurability of many of the measures used for the continuous technical variables represents a potential impediment to their integration into functions whose other arguments are prices and quantities of purchased inputs. The seriousness of the problems caused by this is evaluated in Chapter 4.

Chapter 4

Estimation of the Model

In this chapter, the statistical techniques applied to the models based on Eqs. 2.8 and 2.9 are explained along with presentation of the results of those analyses. Three classes of analysis were performed with the models and data:

1. Pre-estimation reduction of the size of the V matrix.
2. Analysis of the cross-sectional variation in cost between fields based on estimation of Eqs. 2.8 and 2.9 by regression analysis.
3. Analysis of the variation in cost over time by merging the results of the cross-sectional study with rates of change over time in the characteristics of new field discoveries.

Dimension Reduction Analysis

In their matrix form, Eqs. 2.8 and 2.9 mask the large number of variables which have been offered as having a possible significant relationship to the cost of production. The V matrix contains ten continuous and five dummy variables, which with observations on production (X or X'), the cost of capital (r) and the labor/capital ratio (s) makes a total of 18 independent variables in the models. For theoretical and practical reasons, respecifications of the models which preserved the original information, but required a smaller number of variables were sought.

There are two theoretical bases for seeking a reduction in the size of the regressor matrix. The first is the postulate of parsimony: "given two or more equally compatible models for the given data, the simpler model is believed to be true."[41] The second is that is was believed, a priori that there are several essential "qualities" of oil fields captured by combinations of some of the variables in the V matrix.

There were also two practical reasons for reducing the dimensions of V in this case. First is that if there are common factors which undelie certain groups of variables, then the correlation between them would generate multicollinearity in regression estimations. Second was consideration of a degrees of freedom problem which arose in estimation of the models over subsets of the 156 fields of the total sample (e.g., a province), where the numbers of observations were relatively small.

The method chosen for identifying and measuring the overall qualities in the V matrix was factor analysis. This technique "assumes that the observed variables are linear combinations of some underlying (hypothetical or unobservable) factors."[42] Factor analysis cannot be applied to dummy variables, so the nine continuous geologic and engineering variables in V were analyzed. Scores derived from the analysis of factors allow replacement of certain combinations of variables in V, reducing the dimensions of that matrix, and thereby reducing the rank of the regressor matrix.

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41. Jae-On Kim and Charles W. Mueller, Factor Analysis, Statistical Methods and Practical Issues, (Beverly Hills, CA: Sage Publications, 1982), p. 86.

42. The explanation of factor analysis and its use in this study is based on Kim and Mueller, Paul E. Green, Analyzing Multivariate Data, (Hindsdale, IL: The Dryden Press, 1978) and George S. Koch, Jr. and Richard F. Link, Statistical Analysis of Geologic Data, (New York: Dover Publications, Inc., 1974). The statistical estimation was performed using PROC FACTOR of SAS, and PROC SCORE to generate final factor scores. For the regression analysis in the next section, PROC REG was used.

The analytic technique of deriving final factor scores from a (156×9) matrix of raw data proceeded in four general steps:

1. Determination of factors and their loadings. This involved creation of a (9×9) matrix of factor loadings of each of the nine variables (the rows) on an initial set of nine factors (the columns). The first factor is determined by estimation of a function through the data which, because of correlation, are clumped along a given axis. This function minimizes the squared perpendicular distance from each data point to the line. If the data cluster in more than two dimensions, second and higher axes are introduced, minimizing the squared deviations of the data from the function in each dimension. A restriction imposed on the second and all higher factors is that each be orthogonal to all preceding factors. Orthogonality of the factors, in theory, insures that there is no correlation between the factors themselves.

2. Determination of the number of factors to retain. In the first stage, nine factors were introduced which accounted for all of the variance exhibited by the nine variables. For each column vector of loadings (i.e., the factors), an eigenvector and eigenvalue can be determined. Because of the method by which the factor loadings are computed, the factor eigenvalues measure the amount of model variance accounted for by each factor.In order to keep the maximum amount of information from the original data, only the factors which account for large shares of model variance are retained. Several retention criteria exist.

Here, the most commonly used criterion was adopted: keeping factors with eigenvalues greater than one. This method of determining and extracting the factors is principal component analysis.

3. Rotation of retained factors to a more interpretable solution. The hypothesized relationship between the variables and their factor loadings can be illustrated as follows: The overall "size" of an oil field was held, a priori, to be an important quality of the field. "Size" though, consists of serveral measurable dimensions. Here, the variables EUR, SURFACE and POOLS were all believed to join in determining the general size of the field. If this underlying common dimension does exist, then it should be represented by a factor on which EUR, SURFACE and POOLS all have high loadings, and variables not related to "size" - - such as POR or APIGR, would have very low loadings. Given this pattern, unique interpretable factors would be columns where several logically related varaiables have high loadings, and all others are very low. Row-wise, variables would be expected to load heavily on their special one, two or perhaps three factors, with very low loadings on all others. The pattern in the factor matrix is called "simple structure."

Where there is more than one retained factor, the factor matrix produced by principal component analysis is unlikely to exhibit simple structure. However, these vectors can be rotated to an orientation which makes the loading more clearly understandable. For the rotation process, the target matrix is one which exibits simple structure to the greatest extent possible, while preserving the information and orthoganality of the original factors.[43] The process of rotation differentiates factor from principal component analysis.

4. <u>Confirmation of factors and generation of factor scores.</u> From the rotated factor matrix, three factors, each with three high variable loadings became clear, interpreted as: the "size" dimension (SIZE), described above; a composite measure of porosity, permeability (PORPERM) and an index of the "mobility" of the oil (OILMOBL), representing the gas/oil ratio, API gravity and depth. Even in their rotated pattern however, each factor has small loadings of the remaining, generally irrelevant variables. Following Kim and Mueller, variables with factor loadings below .3 were deemed insignificant and their loadings constrained to zero.[44] With these contraints, the factors were reestimated. The result of this procedure is creation of three single-factor models composed only of loadings from variables which were significant in the first estimation. The eigenvalue each factor measures the quantity of variance of the original constituant variables retained by the factor and its score.

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43. The choice of oblique rotation of the factors also exists, but was rejected because of the importance of generating final vectors of factor scores with the lowest interfactor correlation. Orthoganal rotation of the factors does not guarantee orthoganality of final factor score vectors, but will produce a close approximation than the alternatives offered by oblique rotation.

44. Kim and Mueller, op. cit., p. 70.

Factor scores for each observation in the original data matrix represent the linear combination of the variables included in the factor, weighted by their factor loadings and correlations. To produce meaningful factor scores as replacements for the original variables in V, the entire data matrix was standardized (zero mean, unit variance), as the factor-score procedure is debilitatingly sensitive to units of measure.

The final factors, SIZE, PORPERM and OILMOBL were introduced into the regression models estimated on standardized data, replacing the original v_i which composed each respective factor. The statistical significance of these factors in the regressions serve as the test for the validity of the combinations the factors represent.

Results of Factor Analysis

Before final estimates of the rotated factor loadings and factor scores could be determined, decisions on options within the class of factor analyses were made. The overall conclusion from analyzing the (156 X 9) submatrix of V with various constraints on the factoring procedure was that the final results were remarkably stable - - irrespective of the input data format, sample size and the method of factor rotation. This supports the uniqueness of the solutions and raises confidence that the factors and loadings identified are real, and not just creations of the estimation technique.

The models in Eqs. 2.8 and 2.9 specify that the elements of the V matrix be the natural logs of their raw values. This transformation of the V matrix changes the correlations between variables, and consequently, has an effect on the factor solutions. The findings of factor analysis of the raw data and the log data are presented for comparison. Table 4.1 shows factor loadings of the raw data and Table 4.2, the data after log transformation.

There is a choice available in the input format of the data for the analysis: either the (156 x 9) raw data matrix may be used, or the (9 x 9) correlation matrix derived from the raw data. The disadvantage of raw data input is that the analysis is performed only on the observations with no missing values on any variable among the nine in the analysis (71 observations out of 156). Estimation from the correlation matrix takes advantage of the information in all observations, but the effects of performing the factor analysis on a matrix of correlations estimated from differing sample sizes for each variable are uncertain.

For the three factors retained, among the factor loadings of significant variables, the average difference in loadings between raw data and correlation inputs was very small. For Factors 1 - 3 in Table 4.1, the average difference in the loadings was: 4.9%, 8.0% and 14.3% respectively. Because of this stability, the solutions were deemed relatively invariant to both input data formats and sample size. The correlation matrix was used as the input format, as the solution it produced had been generally confirmed by analysis of the raw data.

A decision was also required concerning the method of factor rotation. Restricting consideration to orthogonal methods, two leading options were available: VARIMAX and QUARTIMAX. Both methods were employed, also with the general result of similar solutions, demonstrating the stability of the analysis with respect to the rotation method. For the first three factors in Table 4.1, the average difference between the two rotation methods in the loadings of significant variables was: 0.6%, 1.0% and 0.3% respectively. The

QUARTIMAX method was used because it generated more distinctive factor loadings of each variable on its factor. This was expected, as the rotation algorithm operates on the rows of the matrix.

From the rotated factor pattern, three factors became fairly apparent. The variables EUR, SURFACE and POOLS have very high loadings on Factor 1 in Table 4.1, and other variables have very low loadings on this factor. This was identified as the underlying SIZE factor. The variables POR and PERM have very high, and nearly identical loadings on Factor 2, which reflects their high positive correlation and common expression of the amount of void space in the reservoir and its "connectedness." This factor was given the name PORPERM.

The interpretation of Factor 3 was somewhat less straightforward. Three variables with the the highest loadings: DEPTH, GOR and APIGR may describe the quality of "oil mobility" in the reservoir, or the net energy available for mobilization of the oil toward the wellbore and up to the surface. The greater the depth, the greater the pressure in the reservoir; the higher the gas/oil ratio, the greater the amount of gas, the expansion of which drives oil toward the wells. Finally, the lighter the oil (the higher APIGR), the lower the energy required to move it through a reservoir of a given permeability. The barely significant loading of AVTHIK is attributed to a correlation of average reservoir thickness with depth. This factor was given the name OILMOBL.

There was no clear meaning distilled from the loadings on Factor 4, so following the advice of Fleming to only employ factors with substanitive

Table 4.1

Rotated Factor Loadings Computed on the Correlation Matrix Using QUARTIMAX Factor Rotation

Variable	Factor 1	Factor 2	Factor 3	Factor 4
EUR	0.858	0.016	-0.003	0.211
DEPTH	-0.012	-0.281	0.617	0.083
SURFACE	0.853	-0.178	0.021	-0.084
POOLS	0.616	0.091	0.054	-0.239
AVTHIK	-0.019	0.267	0.316	0.827
POR	-0.108	0.810	-0.061	0.280
PERM	0.036	0.829	-0.117	-0.035
GOR	0.052	0.040	0.808	-0.026
APIGR	0.186	-0.009	0.499	-0.711

interpretations in subsequent regression analysis, Factor 4 was disregarded.[45]

As the specifications of Eqs. 2.8 and 2.9 require that the elements of V be transformed into their natural log values, the analysis was repeated on the logs of the (9 x 9) submatrix of V. Because the correlations between elements of V were not invariant to the log transformation, there were changes in the final factor solutions. The factor loadings from the analysis of log data is presented in Table 4.2.

Though the factor order changed as a result of the transformation, all three of the common factors identified in Table 4.1 appear in Table 4.2. SIZE

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45. James S. Fleming, "The Use and Misuse of Factor Scores in Multiple Regression Analysis," Educational and Psychological Measurement, vol 41 (1981), pp. 1017 - 1025.

Table 4.2

Rotated Factor Loadings Computed on the Correlation Matrix

of the Log Data Using QUARTIMAX Factor Rotation

Variable	Factor 1	Factor 2	Factor 3	Factor 4
LEUR*	0.062	0.880	0.266	0.060
LDEPTH	-0.155	-0.028	0.015	0.720
LSURFACE	-0.398	0.718	-0.285	-0.152
LPOOLS	0.292	-0.585	-0.289	-0.108
LAVTHIK	0.126	-0.020	0.824	0.421
LPOR	0.861	-0.065	0.106	-0.160
LPERM	0.850	0.112	0.029	-0.137
LGOR	-0.177	0.058	-0.006	0.685
LAPIGR	-0.086	0.090	-0.762	0.427

* The L prefix was added to all variables to indicate the natural logs.

is Factor 2, with no significant changes in constituents or loadings. The PORPERM factor is Factor 1 in Table 4.2. In this estimation, LSURFACE has a low but significant loading attributed to a negative correlation of surface area with both porosity and permeability. The OILMOBL factor, identified as Factor 4, was unchanged, except for a higher loading for average reservoir thickness. In Table 4.2, Factor 3 was the uninterpretable factor.

The three factors, SIZE, PORPERM and OILMOBL were factor analyzed independently, using only the variables which had significant factor loadings on them in the initial estimations. From these reestimated factors, factor scores were created for each observation in the original (156 x 9) submatrix of V. The loadings of the three final factors are shown in Table 4.3.

Table 4.3

Loadings of SIZE, PORPERM and OILMOBL Factors

Variable	Loading	Variable	Loading	Variable	Loading
LEUR	0.827	LSURFACE	-0.441	LDEPTH	0.695
LSURFACE	0.758	LPOR	0.880	LGOR	0.627
LPOOLS	0.862	LPERM	0.862	LAPIGR	0.764

The variance in the three variables captured by their respective factors were: SIZE, 55.2%; PORPERM, 57.1% and OILMOBL, 48.7%. The loss of information in the orginal variables in the process of creating common factors was assumed to be compenstated by the identification of the main causes in variation in the variables included in the final factors.

Regression Analysis

As mentioned above, there have been a total of 18 variables offered, within the framework of Eqs. 2.8 and 2.9, as having a possible effect on the cost of crude production. In the last section, three more variables were created: SIZE, PORPERM and OILMOBL. Though these factors would replace up to eight variables in V, a total of six to 18 variables still may enter on the right hand sides of Eqs. 2.8 and 2.9. At this point, empirical analysis was conducted to determine what variables were important in these equations, their quantitative relationship to cost, and to compare models. Multiple regression analysis was chosen to investigate these relations. In this section, the estimable forms of the models are derived, along with an explanation of the methods of statistically testing the hypotheses based on them. This section is followed by one in which the results of regression analysis are presented.

Because the production of both oil and gas from a field is the rule and production of just oil the exception, Eq. 2.9 was considered the general case. Eq. 2.8 is a special case where G = 0 so the subsidy equals zero on the left hand side, and X = X' on the right hand side.

$$(2.9)\quad \ln(C - (P_g G)) = \ln(r) + h\ln(X') - hf_1 \ln(v_1) - \ldots - hf_m \ln(v_m) - hb\ln(s)$$

In this equation, the parameters of interest are h, f_i and b. This vector, W, must be estimated in a two step process because the parameters f_i and b appear in Eq. 2.9 multiplied by h. The first step was the estimation of the parameter combinations, hf_i and hb and the coefficient on production, h. Rewriting Eq. 2.9 in matrix notation, the following form was estimated:

$$(4.1)\qquad C = ZJ$$

where,

C = the vector of dependent variables = $\ln(C - (P_g G))$.

Z = the matrix of independent regressors = $\ln(r)$, $\ln(X')$, $\ln(v_i)$ and $\ln(s)$.

J = the vector of parameters = h, hf_i and hb.

Estimates for the vector J were derived by ordinary least squares. The second step in producing estimates of the vector of original unknowns, W, was to divide the combined parameter estimates for hf_i and hb by the estimate for h. The resultant quotients: f_i and b, (w_i), represent the coefficients of interest, relating the economic and physical variables in Z to the cost of production.

Because the estimates of w_i are the product of division of pairs of estimated values in J, the standard statistic for hypothesis testing (the t-test) must be expanded. This is required to account for the influence of covariance between the estimate of h in J and estimates of the other elements of J which are divided by h to produce the vector of final estimates, W. The appropriate test statistic is:[46]

$$\text{(4.2)} \qquad \frac{w_i}{\sqrt{q' \sum q}} \sim t_{(n,(a/2))}$$

where,

Σ = the variance/covariance matrix from estimation of Eq. 4.1.

q = a vector of partial derivatives of w_i with respect to the parameter estimates, j_i.

Because a prime objective of this study is to investigate the variation in cost of production between fields and as a function of depletion, Eq. 4.1 was estimated for each year of production. Models based on Eq. 4.1 were estimated from the full sample of 156 fields and from subsamples from the Gulf Coast, Mid Continent and Rocky Mountain provinces. Separate estimations for the California fields and the fields of the New Mexico portion of the Permian Basin were not made because of insufficient sample size. These fields were, however, included within the total sample of 156 fields.

To further study the properties of the model embodied in Eq. 4.1 which mixed economic and physical variables, a comparison was made with what might be called a "pure engineering" cost function, in the sense of Chenery and Marsden.[47] The specification of this function differed from Eq. 4.1 in three key respects:

1. The dependent variable was changed to the natural log of average cost, C*, where:

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46. Arthur S. Goldberger, Econometric Theory, (New York: Wiley and Sons, Inc., 1964), pp. 122-125.

47. Chenery, op. cit. and Marsden, op. cit.

$$C* = \ln((C - (P_g G))/X')$$

2. The economic variables, ln(r) and ln(s) were omitted from the matrix of regressors, leaving only the level of production, X'*, and the physical parameters, V*, all of which were in natural logs.

3. The vector of parameters, β, does not represent the combination of other estimates, but are directly the partial derivatives of the C* with respect to the regressors.

Considering these modifications, the competitive function can be written as:

$$(4.3) \qquad C* = \beta_0 + \beta_1 X* + \beta_2 v*_1 + \ldots + \beta_m v*_m$$

In matrix notation, Eq. 4.3 becomes:

$$(4.4) \qquad C* = V*\beta$$

Models based on Eq. 4.1 are referred to in the discussion of results as the "mixed" models, after their hybrid combination of economic and physical variables. The models based on Eq. 4.4 are referred to as "engineering" models. Though the "mixed" models are based on the principles of the engineering production and cost functions, they are the product of standard economic optimization. This is not so with models based on Eq. 4.4.

Results of Regression Analysis

Results of the regression analysis represent the main empirical product of this study. Specifically the following questions must be addressed at this point:

1. What are the physical variables which have a significant effect on the cost of production? In definition of the important dimensions of V, are the factor scores useful in development of robust models?

2. Once final forms of the models based on Eqs. 4.1 and 4.4 are determined, what are the estimates of the coefficients on the included variables? What is the statistical significance of these estimates?

3. How do the performances of models based on the "mixed" (Eq. 4.1) and "engineering" (Eq. 4.4) specifications compare when estimations were based on the total sample of 156 fields and based on the three province-level samples?

Determination of the variables in V having an important, independent relation to the cost of production was made by analysis of their correlations and auxilliary regressions, as well as the factor analysis described above. As indicated by the factor analysis, there were significant correlations between depth and four other elements of V. For the total sample, the correlation coefficients between depth and the gas-oil ratio (GOR) and the API gravity were 0.13 and 0.21 respectively, and all three variables had significant loadings on OILMOBL. Correlations between depth and porosity and permeability were -0.22 and -0.12 respectively. The loading of DEPTH on the PORPERM factor was -0.28, barely insignificant under the 0.3 criterion.

These were anticipated relationships, but they had unanticipated statistical consequences. The direct relationships between depth and hydrocarbon gravity and GOR were expected on the basis of the thermal model of petroleum generation. This theory holds that as burial of a petroleum deposit, or its source material continues, rising temperature and pressure cause larger hydrocarbon molecules to crack, producing successively smaller (lighter) components. Therefore, heavy oils become lighter with depth (raising API gravity), and the gaseous fraction also increases (raising GOR). In the case of porosity and permeability, as burial continues and pressure builds, compaction and cementation close the void spaces between the grains of rock. This reduction of porosity also restricts the channels between the pores, thus lowering permeability.

On one hand, increasing depth means greater energy in the reservoir available to mobilize the oil to the surface under natural pressure (which is a free input once the well is drilled). This effect is enhanced because oils are lighter with depth and have a higher GOR, both factors working to reduce the energy required for mobilization per unit of production. These effects were captured in the OILMOBL factor. However, an additional offset arises from the positive correlation of GOR and depth. It is that higher gas production which attends production from deeper fields directly increases the amount of the gas revenue subsidy to the cost of production, lowering the net cost.

On the other hand, the cost of drilling a single well has a demonstrated direct exponential relationship to depth for reasons given in Chapter 2. Compounding this effect may be additional difficulties (and the cost of resolving them) which are associated with the deterioration of porosity and permeability with increasing depth.

The problem arose in segregation of these competing influences. Given that there are several factors at play working in opposing directions, it was possible to estimate an independent relationship between cost and depth <u>net</u> offsets, but it was impossible to make quantitative statements about the relative importance of the individual components.

Reducing the number of variables involved in the depth relationship by introducing the factor scores PORPERM and OILMOBL did not clarify the situation. The high correlations between the two factors, (due to the correlation of PORPERM and DEPTH), reduced their value as independent regressors. Because these factor scores did not enhance the identification of specific relationships between elements of V and cost, use of the factor scores in further estimation was dropped. The factor analysis did demonstrate that a large part of the variation in observations on V between fields could be captured by a small number of salient features rather than the large set of variables proposed at the outset of this study. One of these features was obviously depth, the factor analysis indicated that the other was size.

Estimation of models based on both the engineering and mixed specifications demonstrated the absence of significant relationships between cost and porosity type, average reservoir thickness, trap type or the number of reservoirs in the field. In the cases of average reservoir thickness and the number of reservoirs, some of the information in those variables was redundant with the physical size of the field (measured in surface acreage). The correlation coefficient between surface area and number of pools was 0.36. Between the surface area and the average reservoir thickness, there was a negative correlation (-0.14), suggesting a geometric relation of reservoir thinning with increasing areal extent.

To capture the dimension of field size, two choices existed: surface area or estimated ultimate recovery (EUR). Statistically, both performed comparably in various specifications of both the engineering and mixed models. However, there were two reasons for rejecting EUR as a summary variable on field size. First was because the measure is invested with an important economic-technologic component. Assessed at any point in time (January 1, 1975 in this case), EUR is the sum of cumulative production from the field and demonstrated reserves. The latter is the quantity of resources known to exist and be producible at current prices and technology. As observations on all other variables in V are invariant to changes in price and technology, surface area was felt to be more compatible with what V represents in the models. The second reason for adopting surface area was that it is a dimension of size that can be easily perceived within the context of economies of scale in production.

Final forms of the models based on Eqs. 4.1 and 4.4 to be estimated from the total sample had the following form for the mixed model:

(4.5) LCOST = f(LLKRATIO, LHCPROD, LYRDISC, LDEPTH,
LSURFACE, PRESDRV, SAND, LREALINT, MCON,
GULF, ROCK)

where,

LCOST = the dependent variable, as defined in Eq. 4.1.

LLKRATIO = the log of the labor/capital ratio.

LHCPROD = the log of annual production.

LREALINT = the log of the real interest rate.

LYRDISC = the log of the year of field discovery.

MCON = a dummy variable for the Mid Continent Province.

GULF = a dummy variable for the Gulf Province.

ROCK = a dummy variable for the Rocky Mountain Province.

For the engineering model, the specification is:

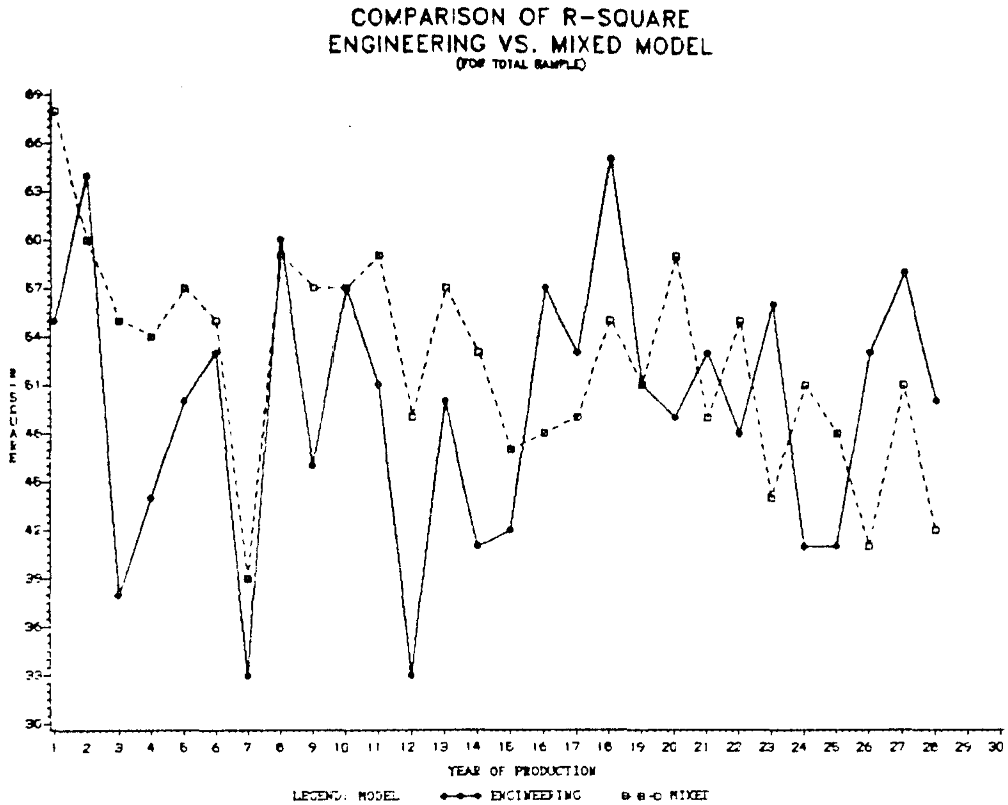
(4.6) LAVCOST = f(LHCPROD, LYRDISC, LDEPTH, LSURFACE,
PRESDRV, SAND, MCON, GULF, ROCKY)

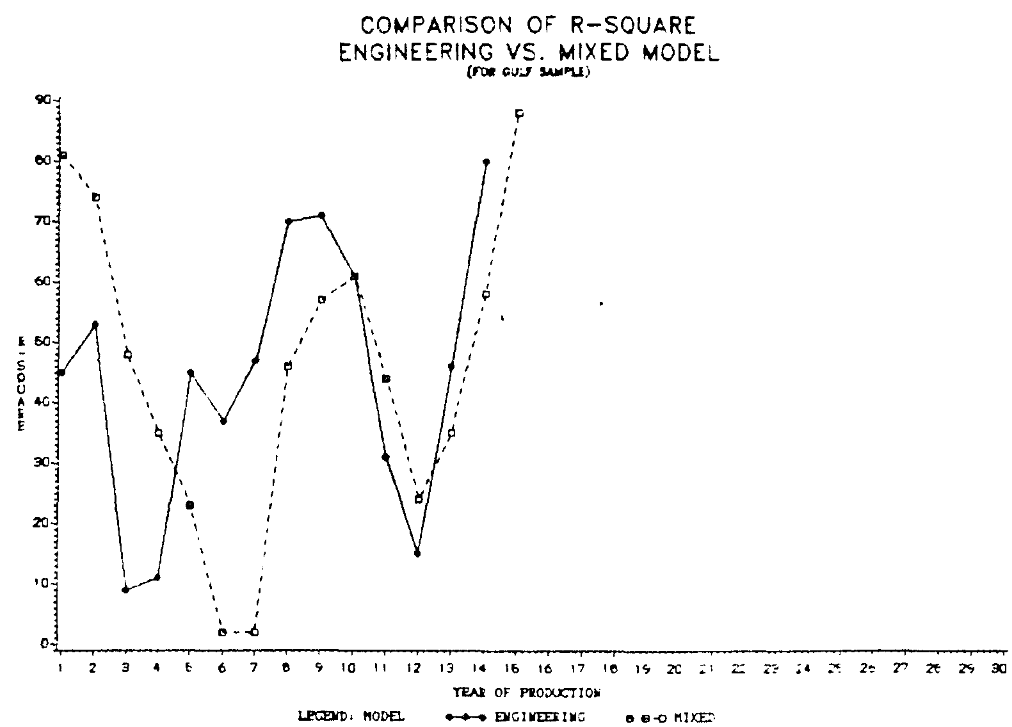
where,

LAVCOST = the log of average cost.

These two specifications were estimated over the total sample of 156 fields. For the three provinces, the province dummy variables were removed and different specifications tested on the assumption that factors important at large, or in one geologic setting may not be important in all environments. Most of the discussion that follows concentrates on the results of the estimation of the models on the total sample. Findings are presented both with respect to relative performances of the engineering and mixed specifcations, and with respect to the individual variables in Eqs. 4.5 and 4.6.

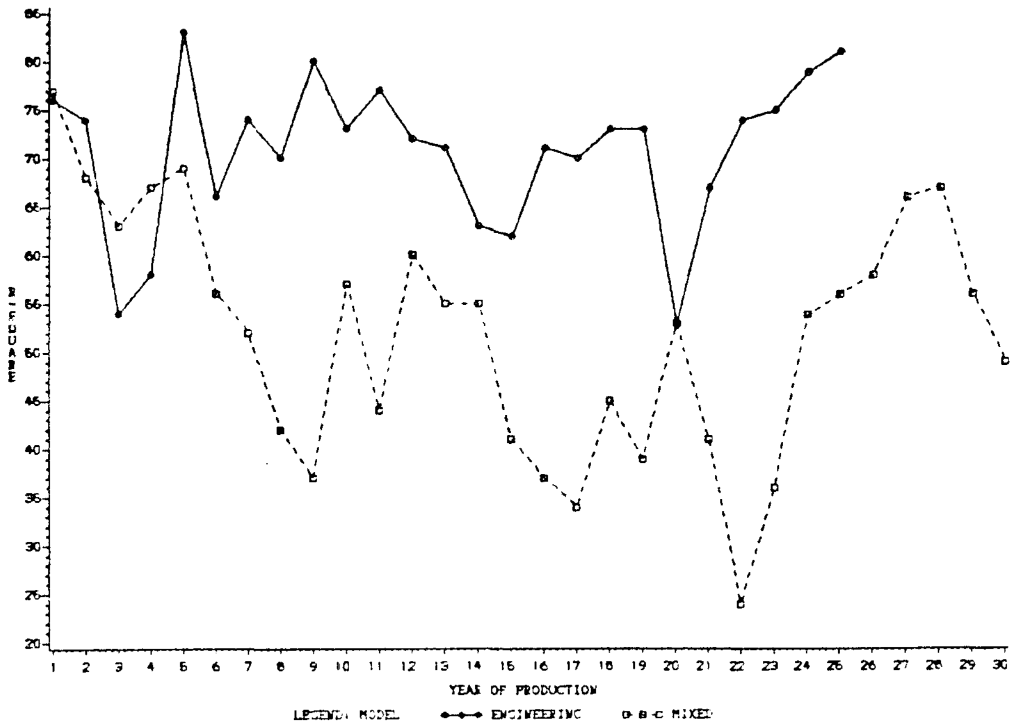
The results of the regression analyses are presented in two series of plots of parameter estimates and statistics. All of the plots are over year of production. Though the entire time series ran for 30 years, in all cases, except the total sample, sample size limited estimation to a smaller number of years of production. This was a serious limitation only in the Gulf, where the time series was reduced to 15 years of production. The first series is the adjusted R^2s from estimation of Eqs. 4.5 and 4.6 over the total sample and three province samples (figure 4.1a through 4.1d). The second series consists of two plots on each variable. The first shows the value of the estimated coefficient (w_i for Eq. 4.5 and β_i for Eq. 4.6) plotted over the year of production. Under that graph is the plot of the t-ratio for the associated parameter estimate in each year of production. In the case of the engineering models, the t-ratio was computed by the division of the parameter estimate by its standard deviation. Computation of the t-ratio for mixed models was conducted using the test in Eq. 4.2. On the graph of the t-ratio, there are two additional lines which indicate the critical values from the t-table which if exceeded lead to rejection of the null hypothesis that the value of the



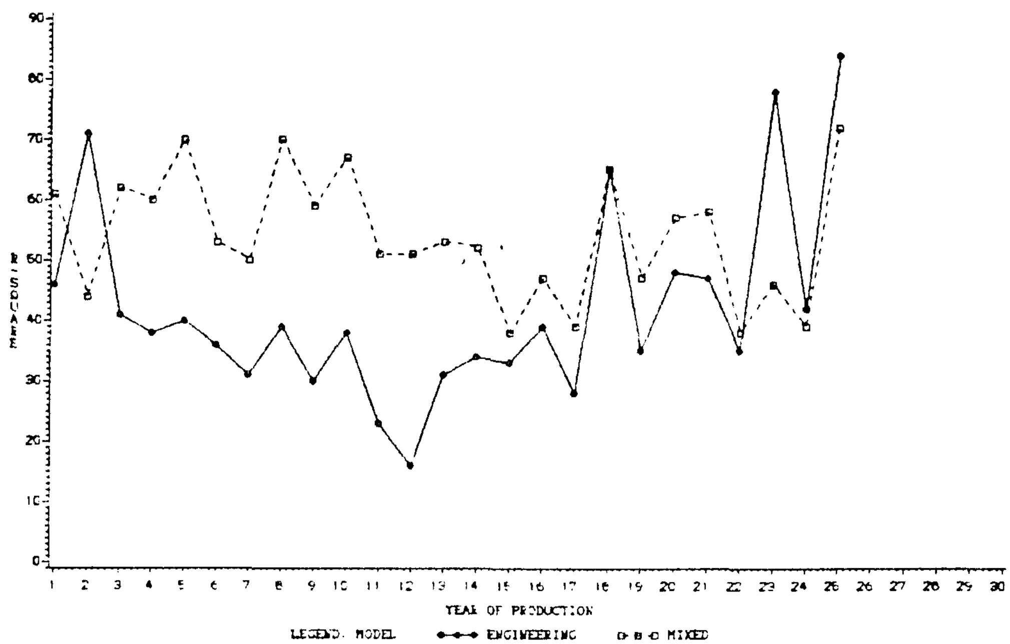


Figures 4.1a and 4.1b

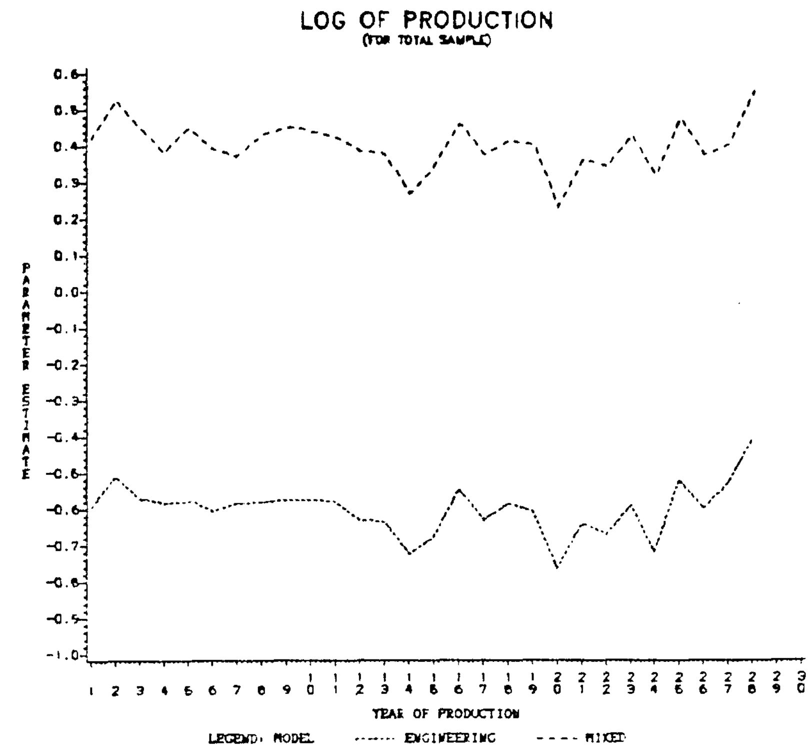
COMPARISON OF R–SQUARE
ENGINEERING VS. MIXED MODEL
(FOR MID CONTINENT SAMPLE)

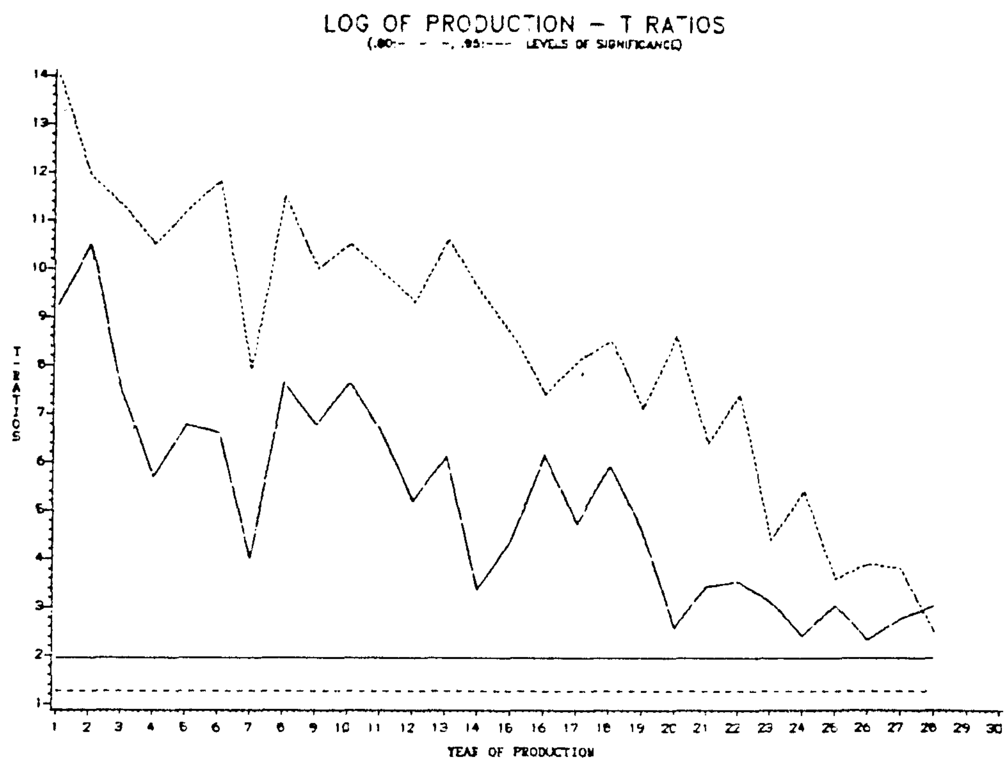


COMPARISON OF R–SQUARE
ENGINEERING VS. MIXED MODEL
(FOR ROCKY MOUNTAIN SAMPLE)

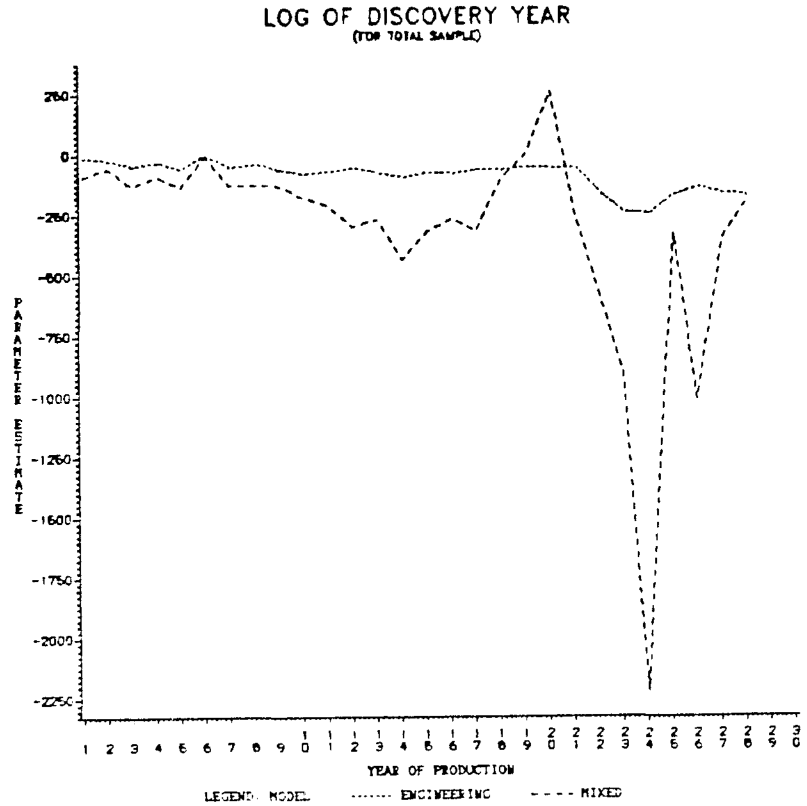


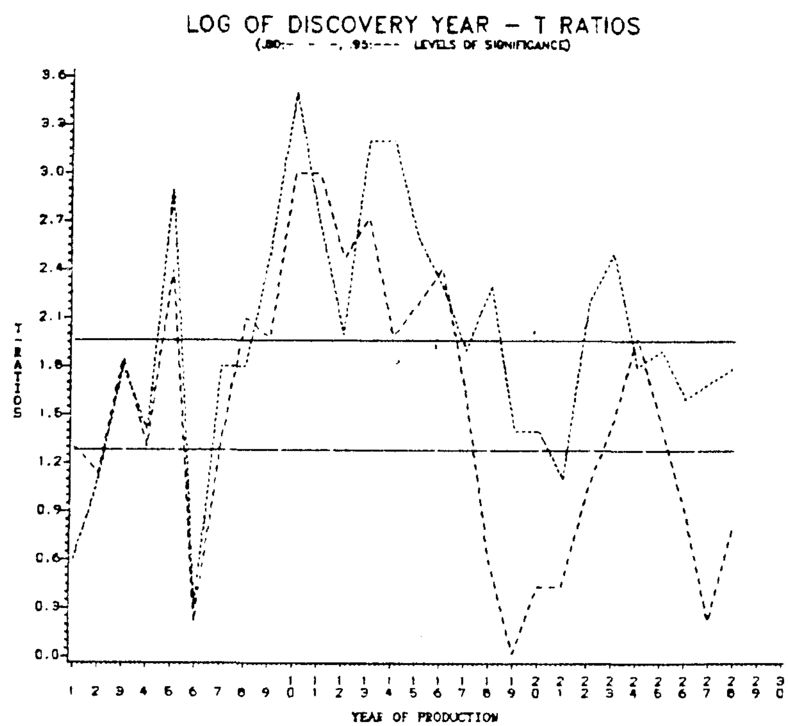
Figures 4.1c and 4.1d



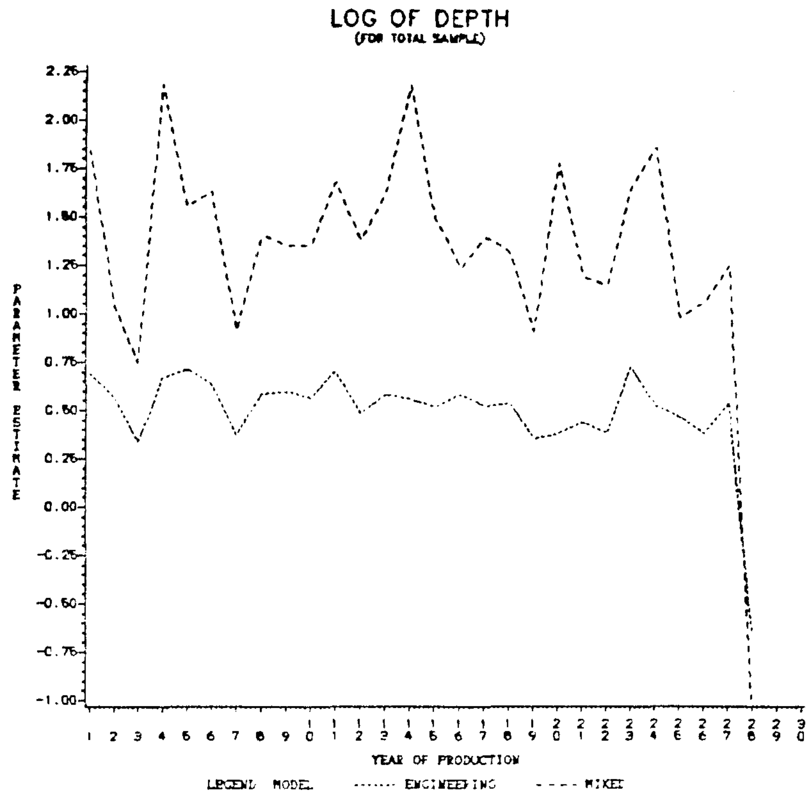


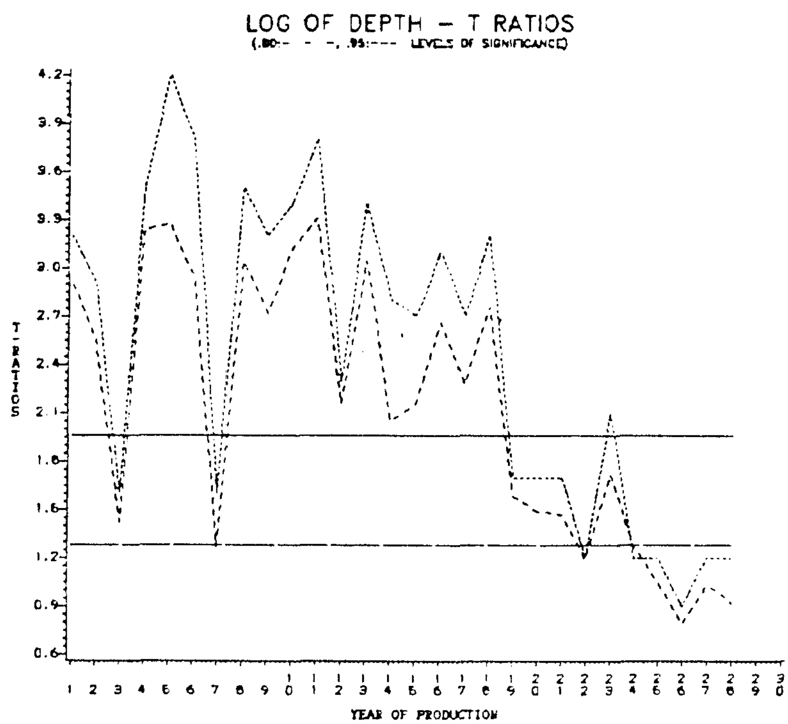
Figures 4.2a and 4.2b



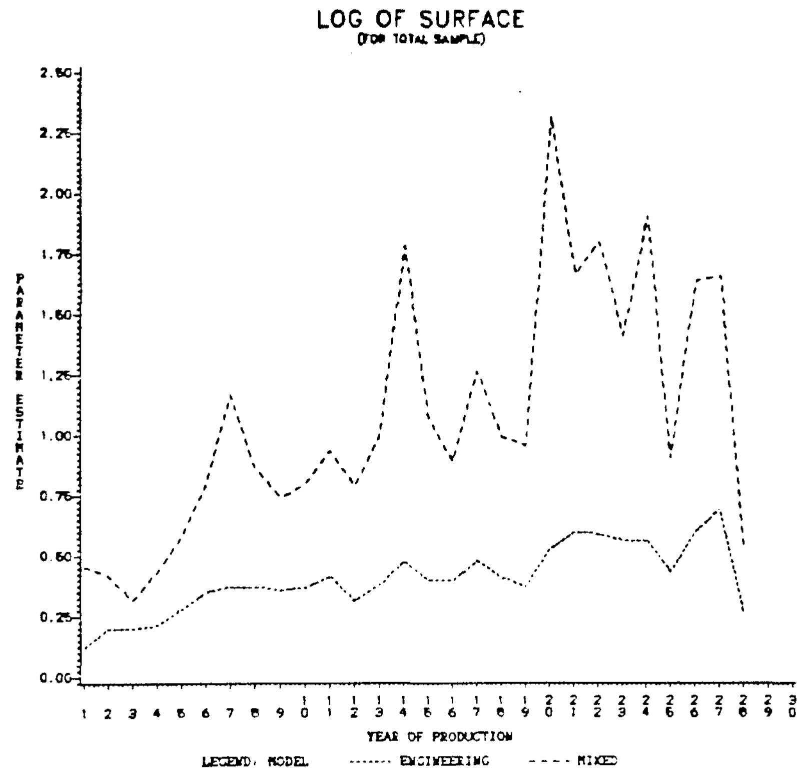


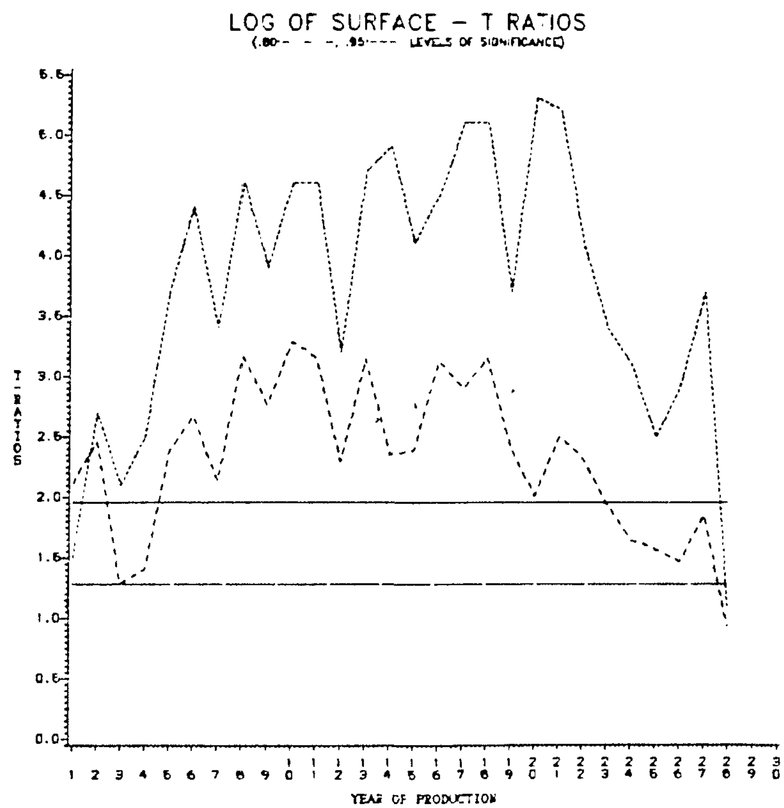
Figures 4.3a and 4.3b



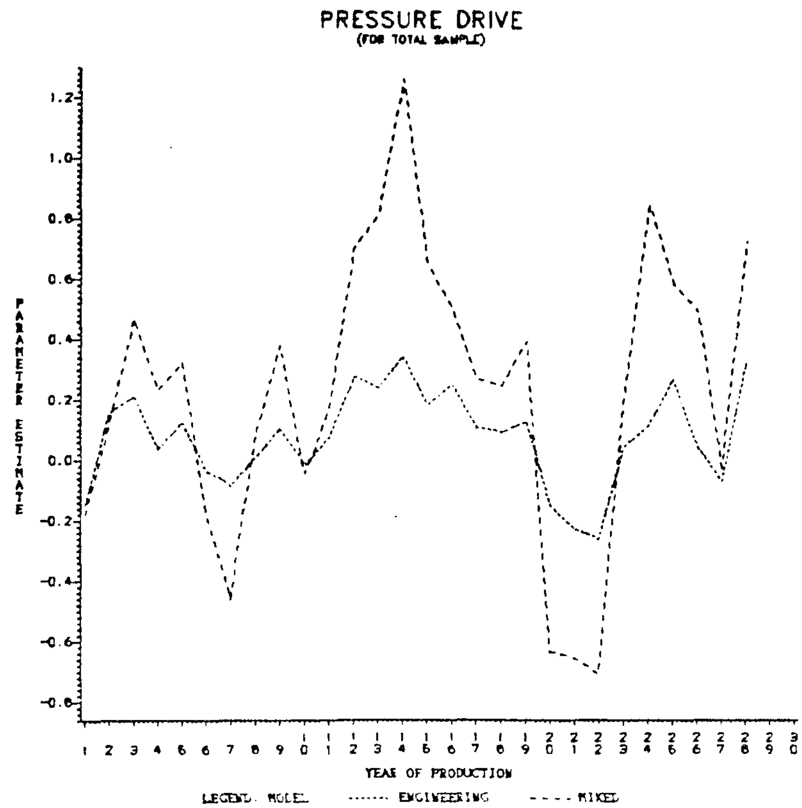


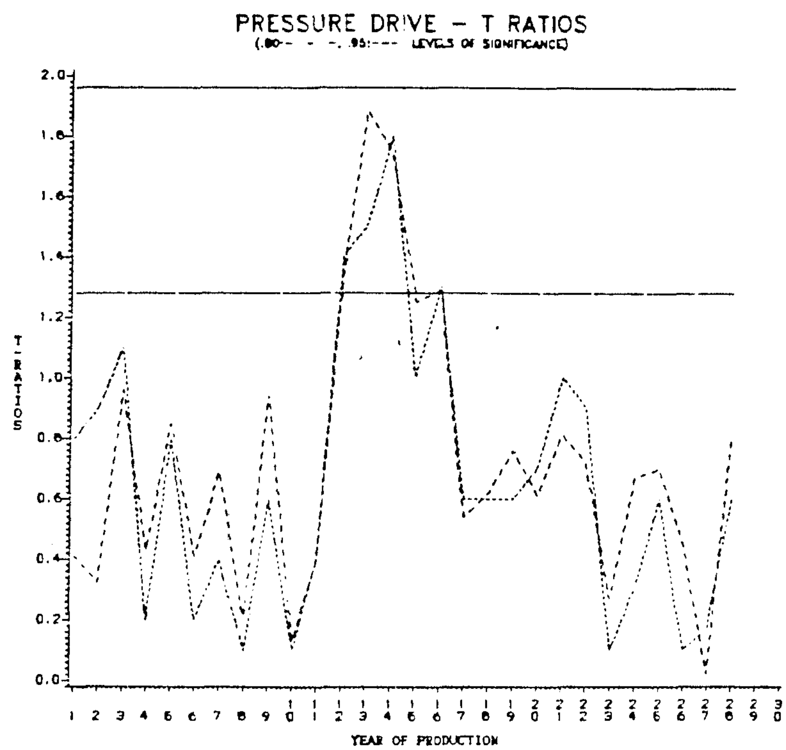
Figures 4.4a and 4.4b



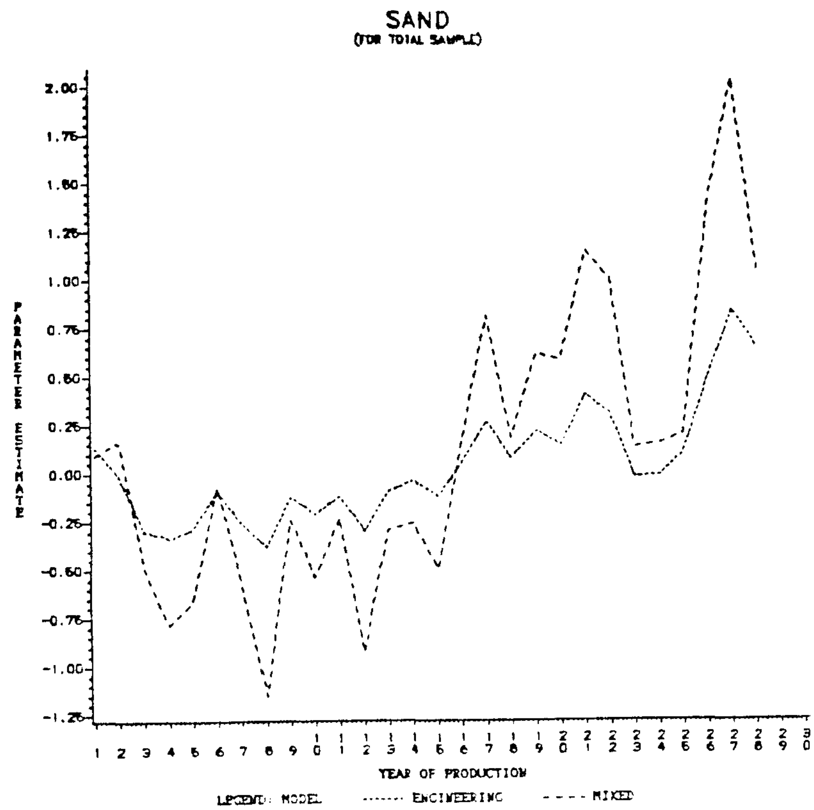


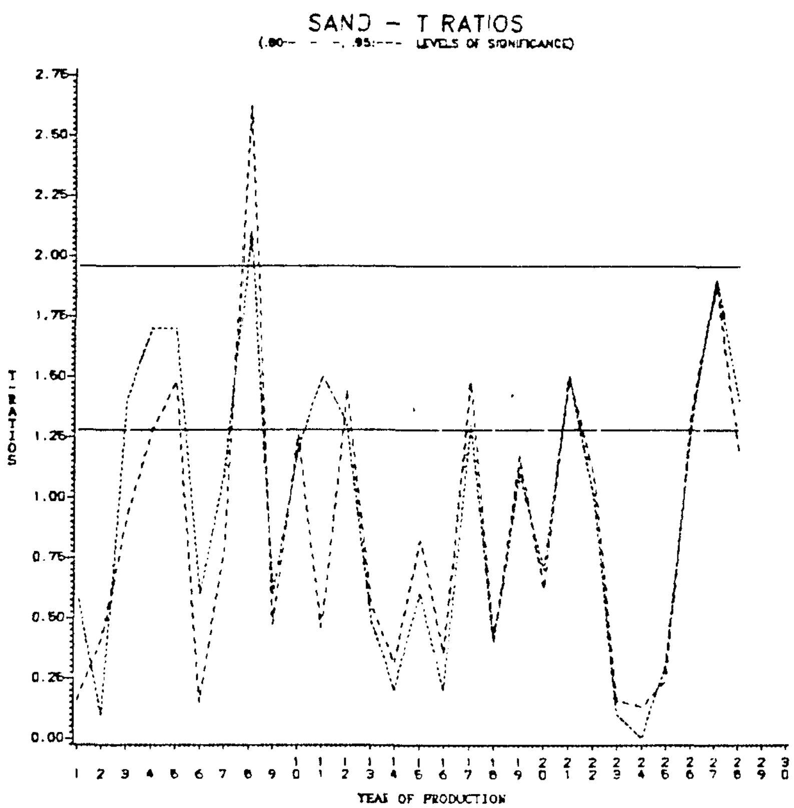
Figures 4.5a and 4.5b



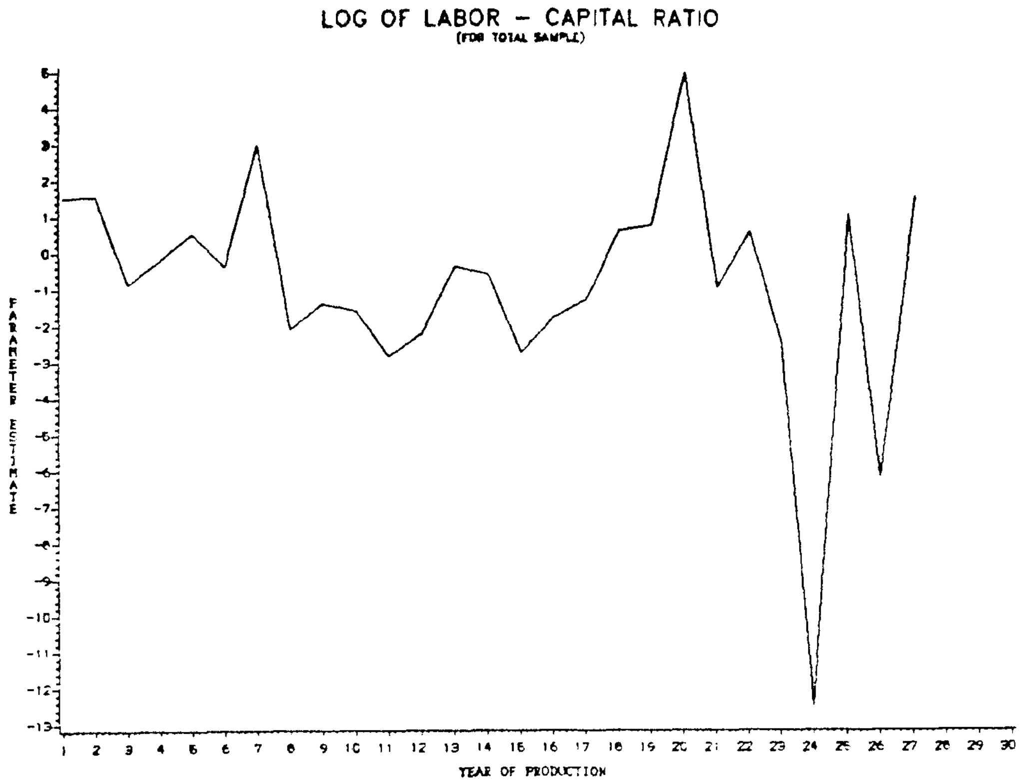


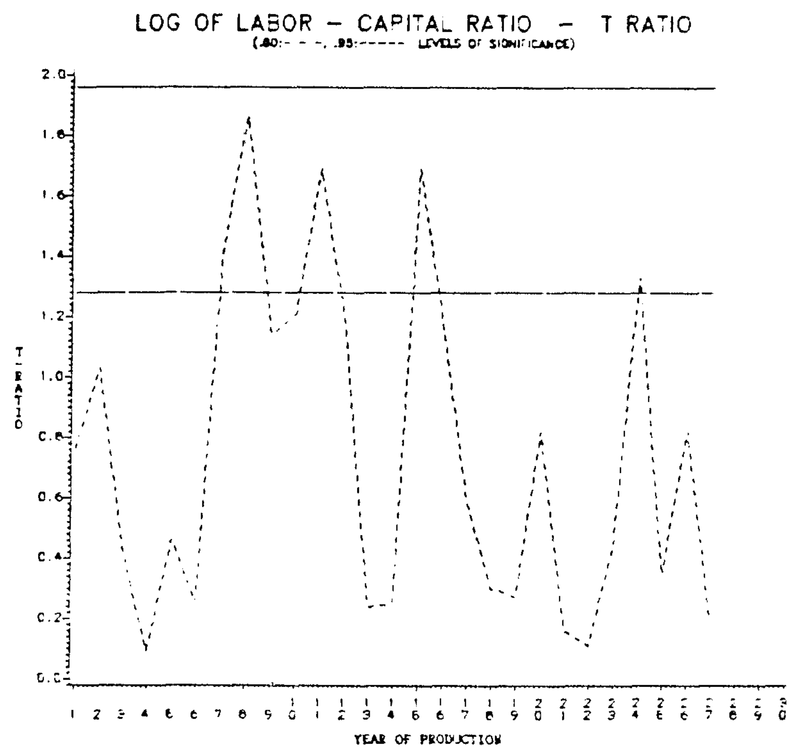
Figures 4.6a and 4.6b





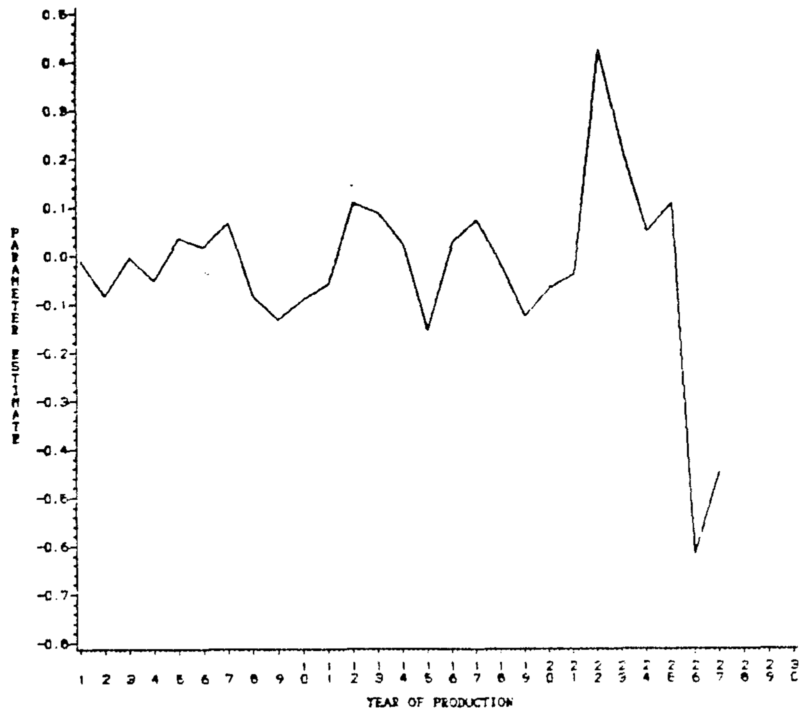
Figures 4.7a and 4.7b



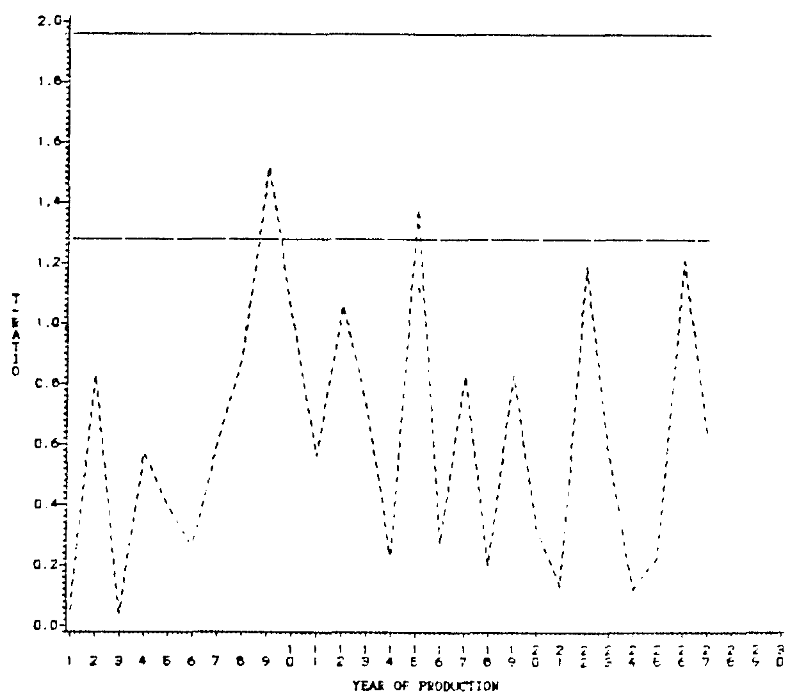


Figures 4.8a and 4.8b

LOG OF REAL INTEREST RATE
(FOR TOTAL SAMPLE)



LOG OF REAL INTEREST RATE – T RATIO
(.80: – – –, .95: ––––– LEVELS OF SIGNIFICANCE)



Figures 4.9a and 4.9b

parameter is equal to zero. The higher line represents a .95 level of significance and the lower, a .80 level. This second series of plots for the models estimated on the total sample are presented in figures 4.2a and 4.2b through 4.9a and 4.9b. The second series for models estimated on the three province samples are presented in Appendix 2, in figures A.1a and A.1b through A.20a and A.20b. The values for both the engineering and mixed models are presented in each case, except for the variables labor/capital ratio (s) and the real interest rate (r), which only appear in the mixed models.

Figure 4.1a shows the adjusted R^2s for the two model specifications run on the total sample. The values track very closely throughout the time series, indicating that the models accounted for, on average, somewhat more than half of the observed variance in the dependent variable. From the beginning, it was realized that factors other than those incorporated in the model could account for variation in the observed costs; the effects of regulation, taxation, market bottlenecks, etc. all play some role in variations in cost. That over half of the observed variation could be accounted for by both models strongly supports the hypothesis that the physical parameters are important determinants of cost. The close results between the two specifications indicates minor roles for the real interest and the labor/capital ratio.

The results of estimation of the models from the three province samples (figures 4.1b - 4.1d) follow the same patterns as exhibited in the total sample. Between the two model specifications, however, the results are divided. In the Mid Continent, the engineering model had consistently higher adjusted R^2s (which was the best of all estimates, judged by that criteria), but this was reversed in the Rocky Mountain sample. On the basis of adjusted

R^2s, the performance of both models was erratic over the short time series of 13 years.

The parameter estimates themselves generally conformed to expectations, both regarding sign and magnitude. For the log of level of production (figures 4.2a and 4.2b), the mixed model produced a parameter estimate which remained stable around a mean of 0.402 throughout the time series. This finding means that there are increasing economies of scale with respect to current production. In the specification of the engineering model, with the dependent variable changed to average cost, positive economies of scale would be indicated by a negatively signed coefficient, with the magnitude measured by the absolute value of the estimate. The coefficient on production has the anticipated sign and an average absolute value (0.6) close to the estimate from the mixed model. Parameter estimates from both models have a very high t-ratio throughout the time series.

The variable year of discovery (figures 4.3a and 4.3b) was included in the models to capture the effects of changes in the cost of production arising out of technological advance. If technolgical changes over time reduced the cost of production on average, fields discovered later should have a lower cost (*ceteris paribus*). Therefore, the expected sign is negative, which was the case with estimates from both models. This finding and the data on the statistical significance of the estimates favor accepting the hypothesis that between two fields which are otherwise alike, the field discovered later, and incorporating more recent technology, will have a lower production cost. This should not be taken to mean that the general cost of petroleum production is expected to continually decline over time. Though fields with the same physical characteristics (particularly depth and size) could be produced more cheaply the later they were discovered, the expected value of depth and size in the set of fields discovered each year is not constant, but a function of time. This relationship is examined in the following section.

The coefficients on the log of depth (figures 4.4a and 4.4b) had the anticipated signs (positive) and generally, expected magnitudes. The estimate of about 1.3 from the mixed model indicates the magnitude of the exponential relationship between depth and cost, net any offsetting influences arising out of increased gas in the production stream or higher reservoir energy. The t-ratio indicates that the significance of the estimates deteriorate after about 15 - 17 years of production. It was concluded that this was related to the time path of drilling in the field. Early in the production cycle, a large number of wells are drilled each year, increasing the total capital stock in a way directly related to the depth of the field. Late in production, when the total capital stock is almost complete, current drilling adds only a small fraction to the existing capital stock, so costs become fairly insulated from depth.

The log of surface area (figures 4.5a and 4.5b), taken as the variable best representing field size, also had the expected sign (positive). The coefficient on this variable reflects the economies of scale with respect to physical capacity (as opposed to current production, the positive short run economies of scale). A value of the coefficient which is < 1, means economies of scale exist. The parameter estimates between the two models both start below one, both rise, and the estimate from the mixed model is > 1 after about the 14th - 18th year of production. Given the significance of both sets of estimates, two conclusions can be drawn. First is that positive economies of scale do exist with respect to field size measured by surface acreage. The second is that the degree of economy deteriorates over the life of the field. It is easy to imagine how in a very spatially extensive field with many wells, in the final stages, a large number of low production wells over the large area would be a greater burden relative to a smaller field.

The dummy variables for pressure drive and sand reservoir lithology (figures 4.6a - 4.7b) were retained in Eqs. 4.5 and 4.6 because they did produce intermittently significant results (at the 0.80 level), they improved the general performance of the models as measured by adjusted R^2 and there were strong a priori reasons for expecting these variables to be important, as explained in Chapter 2. Because of the low t-ratios, it is hard to invest much faith in the quantities expressed in the parameter estimates. In the case of both variables, they were found to be more important in the models estimated over the province samples.

Of the two economic variables, the log of the labor/capital ratio (figures 4.8a and 4.8b) was insignificant throughout the time series. The t-ratio in figure 4.9b on the log of real interest tests the null hypothesis that the parameter value is equal to zero, which was not rejected. Because the log of interest enters Eq. 2.9 without an explicit coefficient, the implicit value of the coefficient on the log of real interest is 1. Testing the null hypothesis that this parameter is equal to 1 resulted in not rejecting the null hypothesis in many years over the time series. This supports a significant role for the cost of capital in determining the cost of production of crude oil. The fact that the log of interest is simply an additive term in Eq. 2.9 does mean that though statistically significant, its relative importance in determination of cost is small.

Of the three estimations at the province level, the models for the Gulf Coast Province (figures A.1a - A.7b in Appendix 2) performed worst of all: measured by adjusted R^2, the stability of the individual parameter estimates, and their statistical significance. The values for the coefficient on the log of production were close to that for the total sample, though the estimates from the mixed model were insignificant throughout much of the time series. Both models produced erratic results for the estimate of the coefficient on the log of the year of discovery. Parameter estimates on the log of depth corresponded to those of the total sample through the 12th year of production, though the mixed model produced an estimate which was consistantly insignificant. Estimates of the coefficient on surface area were insignificant in almost all years. The parameter estimate on the variable sand was significant during the third quarter of the time series, entering with a negative sign indicating that cost would be lower in sandstone fields relative to those of limestone or mixed lithology. The findings with respect to the two economic variables for the Gulf Coast Province were about the same as for the total sample.

Results for the models for the Mid Continent Province (figures A.8a - A.14a in Appendix 2) were very close to those for the models estimated over the total sample. Particularly close were the parameter estimates and significance of the coefficients on the log of production, depth and surface area. The estimates on year of discovery had the same sign and were of the same orders of magnitude, but the estimates were radically different after the 20th year of production. The dummy variable for pressure drive in the reservoir was intermittently significant at both the 0.95 and 0.80 levels. The positive sign on the parameter means that in fields where reservoir energy from liquid and gas expansion was not augmented by water or some other drive mechanism, the expected result would be higher production costs. The estimates and significance of coefficients on the economic variables was also generally the same as for the total sample, except that the estimate of the coefficient on the log of real interest were much more erratic.

The performance of the model in the Rockies (figures A.15a - A.20b) was intermediate between what was received in the two other provinces. The coefficient on the log of production indicated that the economies of scale with respect to current production in that area were smaller than in the other two and smaller than the average based on the total sample. The coefficient estimates on the log of discovery year were similar to that from the total sample, except the differences between the fairly stable engineering model estimate and the highly variant mixed model estimate was more profound in this case. Estimates for the coefficient on the log of depth varied around zero throughout the time series, and they were consistantly insignificant. This was attributed to the fact that the variance in average field depth in the Rocky Mountain sample was the lowest of all four samples in the study. The parameter estimate for the log of surface area was very close for the engineering model, but the estimate from the mixed model had several wide swings. The results with respect to the economic variables were about the same as for the total sample.

The results of estimation of the models on all four samples indicated several conclusions from the regression analysis:

1. The relationships between cost and the variables included in Eqs. 4.5 and 4.6 account for an important quantity of the

cross-sectional variation in the cost of production at the field level.

2. Two types of economies of scale in crude oil production have been demonstrated: economies with respect to current production and economes with respect to physical size, interpreted as a long run return to plant size. Additionally, the economies enjoyed early in production on account of size apparently deteriorate as the field is depleted.

3. In addition to surface area, the other clearly important variable in all areas was depth. Though the average cost increased with depth, the higher cost of drilling deeper wells was partially offset by a reduction in the number of wells required for production.

4. The economic variables, labor/capital ratio and real interest did not play a large role in any of the estimations. However, the importance of real interest was greater than the labor/capital ratio.

Variation in Cost over Time

In the last section, the structural parameters in Eq. 2.9 were estimated, along with the parameters for the engineering model described by Eq. 4.6. These data give information on the cross-sectional variation in cost of production between fields, but do not in themselves say anything about how and why variation in the unit cost of petroleum may arise over time. It is the variation over time which reflects on the utility of unit cost as a measure of scarcity.

At the outset of the study it was stated that the physical variables were not the sole determinants of cost. The statistics on adjusted R^2 presented in the last section verify that neither the engineering nor mixed model was a complete specification of the cost of production. It is possible, however, to draw conclusions about the time paths of those components of cost related to the physical parameters. More generally, this is the variation in cost over time due to changes in the quality of the resource base. With these changes, the influence of technological change must be considered.

Trends in the unit cost of production arising out of changing field depth, size or productive capacity can be inferred by combining results of the cross-sectional study with analysis of the changes in the average values for these characteristics among the fields discovered each year. Given the determination of economies of scale in production and the positive relationship between depth and cost, if the trend in discoveries is toward deeper and smaller fields, cost would be driven up. If new discoveries were shallower and larger, the tendency would be to reduce cost over time, as long as the trends continued among the newly discovered fields. The effects of dynamic changes in the resource base, net of the influence of technologic change, constitute a lower bound to the cost of production, because the time paths of variables such as depth and size of new discoveries cannot be chosen by the firm.

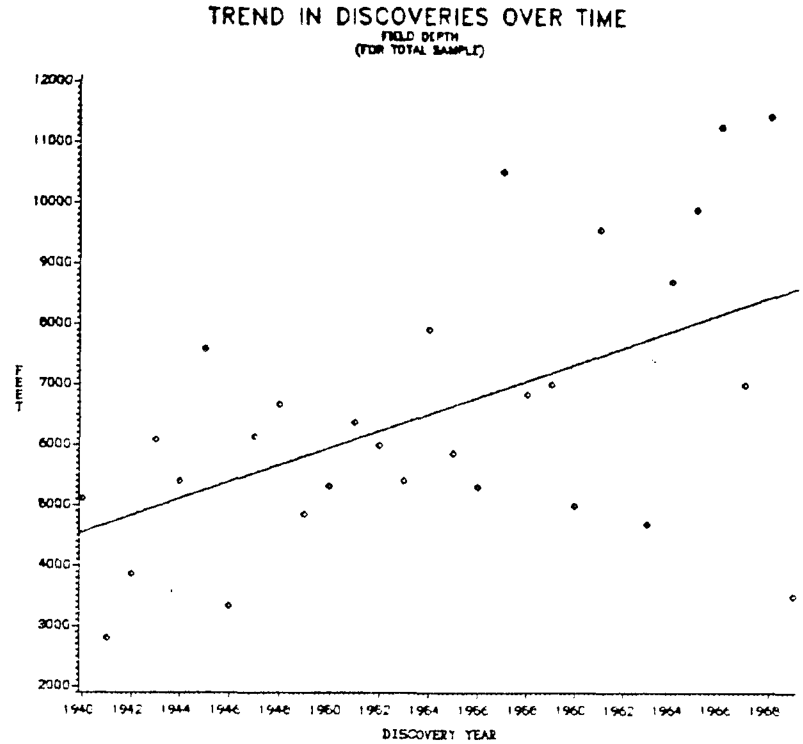
For the total sample of 156 fields, and for the Gulf, Mid Continent and Rocky Mountain provinces, the average depth, surface acreage and EUR were determined for the field discovered each year between 1942 and 1972. The rates of change in surface acreage and depth with respect to time are indicated by the slopes of the regression lines in Figures 4.10 and 4.11.

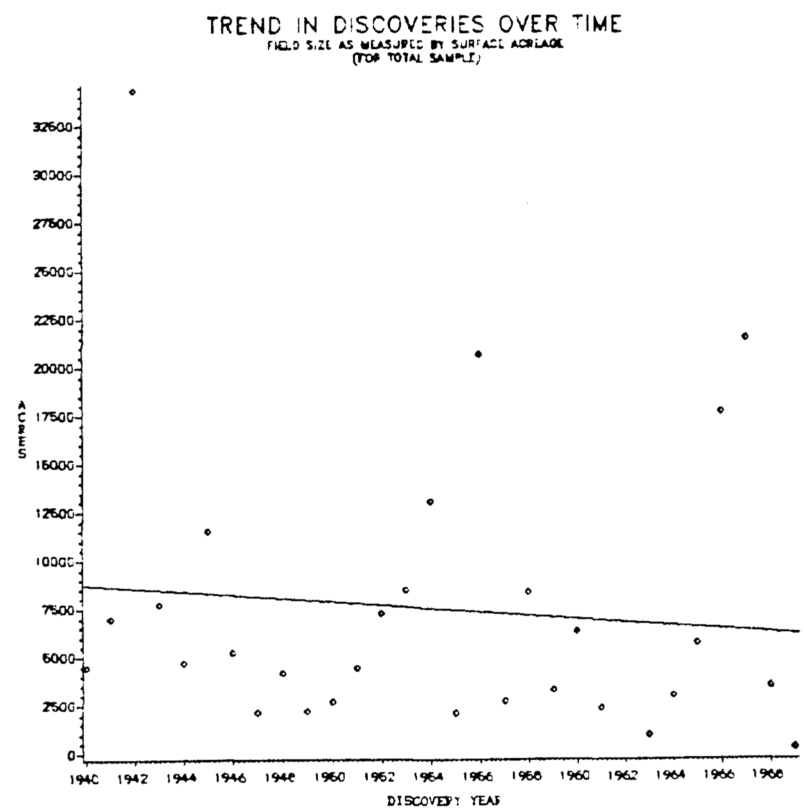
Ideally, the field's life-time average annual production should be used to measure the changes in the average productive capacities of fields. The life-time averages are, of course, not available. Unfortunately, even if average production were computed between 1942 and 1972, many fields discovered in the 1960s would not have reached a level of production before the end of the time series that would be a meaningful measure of productive capacity. This would artificially magnify any actual drop over time in the productive capacities of newly discovered fields.

EUR was adopted as the measure most closely proportional to the life-time average productive capacity of the field. The change in the average EUR of discoveries between 1942 and 1972 was used as the change in the variable average annual production. Data on the average EUR of discoveries in the total sample, and the regression of that variable on time are shown in Figure 4.12. The plots for the three provinces of these three variables are shown in Figures A.21a - A.23c, in Appendix 2.

In the cases of all four samples, the strongest relationships were between depth of new discoveries and time. The trends are clearly positive. In the case of the total sample, the average depth of new discoveries rose 176 feet annually, a rate of 2.4% evaluated in the mean year of the time series, 1956. The null hypothesis that this parameter is equal to zero is rejected at a .99 level of significance.

For the total sample, the trend of surface area of new discoveries was negative, but only slightly, declining 21.5 acres/year. Using the t-test, the null hypothesis that the parameter is equal to zero was not rejected. The trend of surface area in the Mid Continent sample was very close to that for the total sample. In the Gulf, however, the relationship was significant and





Figures 4.10 and 4.11

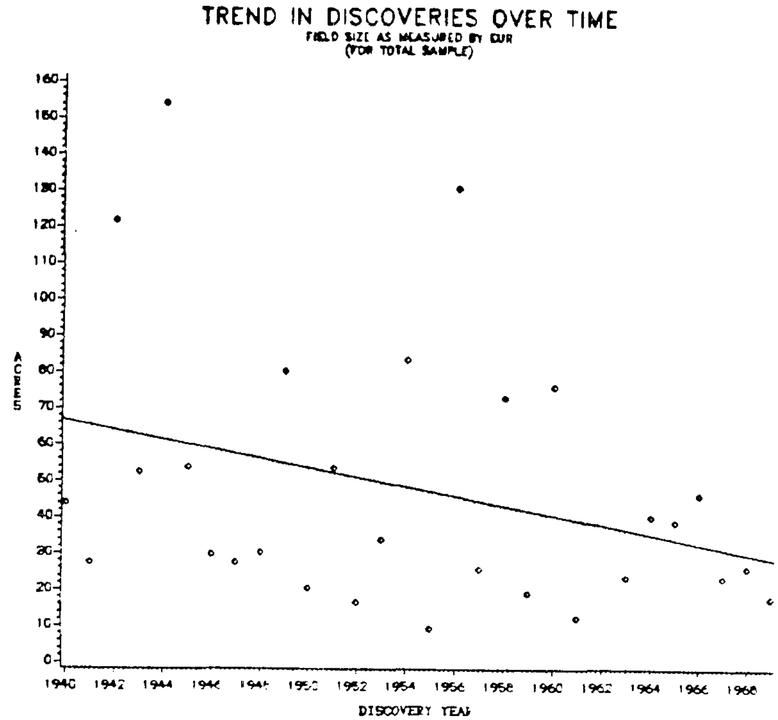


Figure 4.12

of a greater magnitude (-202.4 acres/year, for a rate of change in the mean year of 5.9%). In the Rockies, the average surface area of new discoveries increased throughout the period.

In all four samples, the trends in EUR over time followed the trend of surface area: negative for the total sample, Mid Continent and Gulf and positive for the Rockies. The rate of decline for the total sample was 550,000 BOE/year (evaluated in the mean year, a 1.1% annual rate of decline). The increases in EUR and surface area in the Rockes was attributed to the degree of maturation in that petroleum province. As of the end of 1974, the U.S. Geological Survey reported that in the Rocky Mountain Province, only 41.7% of the oil estimated to be ultimately recovered from the region had been found and either produced or classified as demonstrated reserves.[48] That is, over half the oil was still in undiscovered fields. For the Gulf, this fraction of resources remaining to be discovered was only 29.9% and 28.9% for the Mid Continent. The general pattern of discovery in a region is one in which field size increases in the early phase, followed by a decline. The Gulf, the Mid Continent, and the country as a whole had gone into the decline phase by the early 1970s, but that point had not been reached in the Rockies.

With the exception of the Rockies, the trends were toward smaller and lower capacity fields, and in all areas toward deeper fields. Using the parameter estimates derived from the cross-sectional analysis, it was possible to compute the changes in average cost over this period arising out of these trends in discoveries. Using the parameters from the engineering model, estimated over the total sample, the 2.4% annual increase in depth produced a 1.6% increase in average production costs, holding all other variables constant. The annual decline in productive capacity of 1.1% over the period produced an annual increase in average costs of 0.8%. Change in cost associated with surface area was not computed because its rate of change with respect to time was statistically equal to zero.

The influence of improving technology between 1942 and 1972 must be added to the effects of deteriorating deposit quality to establish the net effect on unit cost over time. Capturing this influence was the motivation for the inclusion of the variable year of discovery in the various models. However, at least one factor other than technology contributed to the negative sign and magnitude of the coefficient on the year of discovery in

48 . U.S. Geological Survey, Circ. 725, op. cit.

the models. That was the 35.1% real increase in the wellhead price of natural gas between 1942 and 1972. As gas price directly determined the value of the subsidy, a field discovered later would enjoy a larger subsidy per MCF of gas produced - - just because the price rose with time, not for reasons related to technology. So, this influence was removed from the assessment of impact of changing technology on cost.

An estimate of the net change in production costs between 1942 and 1972 for the total sample was made by solving the estimated cost function using the values of the variables for 1942 and 1972. This produced an estimate that, accounting for technology and changes in deposit quality, average costs fell at a rate of 1.8% per year. Subtracting the portion of this which was attributable to the rise in natural gas prices, the net annual drop in average production costs was 0.74%. This finding supports the hypothesis that over the period studied, the increases in cost due to deterioration of the quality of new additions to the resource base (discoveries) were exceeded by improving technology, to reduce unit cost.

A very important qualification must be added to this conclusion. That is that the parameter estimates on the year of discovery became both very erratic and statistically insignificant toward the end of the time series (mid to late 1960s) in both models and in all samples. Both factors suggest that the regression regime with respect to this variable may have been changing and that the time path after the break might be different than during the study period. In light of the instability, forecasting continued net declines on the basis of the 1942 - 1972 experience cannot be supported.

Chapter 5

Conclusions

At the outset of the study, several goals were defined. The most important was to investigate the relationship between the natural habitat of crude oil and the average cost of extracting it. Incorporation of field characteristics into production and cost functions was adopted to empirically measure the impact of those parameters on cost, and to learn if information on the time path of unit cost could be obtained which would enhance its value as a measure of scarcity.

The physical characteristics found to have clear impacts on cost were field depth, and surface area. Production costs were also responsive to the average rate of annual production. Though the productive capacity installed, and annual production are chosen by producers, the field's maximum capacity and production are bounded by the "maximum efficient rate" of production and therefore determined by the field characteristics which are given to the firm, rather than chosen.

A number of variables beyond size and depth were proposed as possibly influencing cost. The results on those variables fall into two categories. The first group is composed of the variables correlated with depth: gas-oil ratio, API gravity, porosity, permeability and generally, the level of energy in the reservoir. The individual influences of these variables on cost were found to be more complex than what the models and data could segregate. The estimated coefficients on depth indicated that field-wide average production cost increased with depth, but at a rate lower than the rate of increase for individual wells. This means that efficiencies gained in the number of wells required for production from deeper fields partially offset the expenses of drilling deeper individual wells. The offset created by a smaller number of wells is attributed to the combined influence of oil which is easier to move because of higher gas content and API gravity and the greater amount of energy available to move that oil to and up the well to the surface.

It should be noted that this offset is expected to decline over time, because the fields discovered each year were both deeper and smaller. As the number of wells required to drain the field declines with size, the field-wide average production cost becomes more closely tied to the average cost of drilling individual wells. In the limit, when a field only requires one well, the average cost is equal to the drilling cost of that well.

For the variables not associated with depth: number of pools, average reservoir thickness, lithology, drive mechanism and trap type, only two were found to play roles in any of the samples (lithology and drive). Generally, the finding was that there were no clear relationships between these variables and the cost of production. In some cases, that may be all that is to be said. In other cases though, the relationship may have escaped the data and methods used here, or the influence could fall at a different stage in the production process. For instance, trap type is much more likely to affect exploration costs than the cost of drilling and production. In the cases of reservoir thickness and lithology, impacts may be clearer when considering the efficiency of investment in enhanced oil recovery (EOR) techniques. For the costs of production associated with drilling the field, it must be concluded that these field characteristics are of little importance.

The effects of depth and size on production costs is not startling. Fisher had measured the rate of increase in cost due to increasing depth based on national data and Arps and Roberts measured economies of scale arising out of field size in the Denver-Julesberg Basin.[49] Though they had not been integrated into a single cost function for a field, their joint effect was expected to follow the directions and magnitudes established in these earlier studies. However, only by considering the problem of average cost from the field, rather than the cost of drilling individual wells, could offsets to the influence of depth be demonstrated. Though Arps and Roberts considered field-wide cost, because of the uniformity of depths in the Denver-Julesburg Basin, no variation in cost by depth was reflected in the Arps and Roberts study. As the values of both variables change over time among newly discovered fields, considering both factors will produce more reliable estimations of the time path of costs than extrapolation from the results that were limited to either individually.

Though decomposition of the cross-sectional variation in cost between fields is interesting, the important information is its change over time. What will happen to cost as the average characteristics of the cross-section change over time - - old fields leaving the resource base, and new discoveries being added? This process is contemporaneous with the advance of production technology. It is the net influence of changes in deposit quality and the technological responses to it which determine the time path of costs. The qualified finding on that time path for oil production was that between 1942 and 1972, real average production costs declined in spite of deterioration of deposit quality among the new discoveries.

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49. F.M. Fisher, and Arps and Roberts, op. cit.

This finding is empirically consistent with those of Fisher and Norgaard, who found drilling costs dropping over time (as late as 1968) despite increases in average drilling depth.[50] If this trend of lower unit costs in the face of declining deposit quality could be expected to continue, it would have two implications. First is that unit cost could clearly be rejected as a useful estimator of the physical exhaustion of oil and gas resources. Secondly, continued declines in unit cost would allay concerns about "resource drag" on economic growth, or the sacrifice of other economic goals which are important to society.

Though high confidence can be invested in the empirical finding of a 0.74% annual drop in cost for the total sample over the thirty years under study, evidence was produced which weighs against the proposition that this trend can be expected to continue. There are two reasons for this. First is that, as mentioned in Chapter 4, parameter estimates for the coefficient on year of discovery became both erratic and statistically insignificant at the end of the time series in all samples, for both models. Though the estimated coefficient was valuable for evaluating the function for the period 1942 - 1972, it could not be relied on beyond the point where its consistency and statistical significance ended. If a structural break in the regression regime was signalled, then the appropriate response is estimation of a separate model starting in the late 1960s. Only with data through the 1970s would it be possible to learn if the instability and insignificance of the estimate was a

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50. Fisher, ibid., and R.B. Norgaard, "Resource Scarcity and New Technology in U.S. Petroleum Production," Natural Resources Journal, vol. 15 (1975), pp. 265-295.

transient episod in an otherwise consistent trend, or if the coefficient had acutally turned to zero, or reversed signs.

Without the data through the 1970s, it is impossible to confirm a structural break in the regression relationship and it is difficult to speculate why this may have been occurring. However, 1970 is coincident with three turning points which may have affected the regression regime. First is that in the late 1960s, the real cost of capital rose to levels which were unprecedented in the time series. The second reason is that the period around 1970 was the beginning of a new direction in energy prices. Both of these factors are very important inputs in the drilling industry, so the changes in absolute and relative prices of inputs may have been sufficient to create a break in the regression relationship, as it had existed since 1942.

The third possible reason for a break is that 1970 also marked the point where annual production exceeded additions to reserves from new discoveries. This marked the beginning of the declining phase of production from the U.S. as a whole. There is no theoretical basis to believe that technological advance would be less efficient in offsetting deteriorating deposit quality during the decline of productive region than it was while the production base was growing. However, the peak in production and the reserve-to-production ratio may be indicators of broad phases in the productive cycle, the latter stages of which are characterized by waning efficiency of investment in production technology.

The second reason for questioning the permanence of the resource-augmenting role of technology arises from the fact that newly discovered fields were both deeper and smaller. If all fields were the same size, their contribution to total supply would be close in any year, and they would be expected to produce for similar periods of time. No field, or group of fields with common cost structures would dominate production, or computation of its average cost. Homogeneous field size is not the case though. Larger fields, discovered early, occupy a larger share of production for a longer period of time than smaller fields. Therefore, increases in cost from smaller, deeper fields added to the resource base at the extensive margin was cushioned. The contribution of these new discoveries to total production remains low as long as the giant fields are producing.

The discovery of the nation's largest fields was concentrated in the 1930s, a trend reflected in the total sample (Figure 4.12).[51] Production from the giant fields discovered in the early forties still dominated total production in the sixties when new discoveries in the total sample were smaller and deeper. By the 1970s and 1980s, the role of the oil giant fields had waned, a process that will continue. From that point on, the resource base was characterized by a declining mean field size, with a smaller variance, as the fraction of very large fields in the sample were withdrawn and not replaced by later discoveries of the same size. As this occurs, the cushion against higher cost discoveries shrinks and average production costs across all fields approaches the cost of replacing reserves at the margin.

The cost of replacing reserves at the extensive margin involves three components. First is the cost of discovery, second is the cost of primary and secondary production, third is the cost of enhanced recovery operations.

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51. J.D. Moody, et al, "Giant Oil Fields of North America," in Michael Halbouty, ed., The Geology of Giant Oil Fields, AAPG Memoir 14, (Tulsa, OK: American Association of Petroleum Geologists, 1970), pp. 8-18.

Data are not available on discovery costs, but it is reasonable to assume that as the population of undiscovered fields becomes increasingly dominated by deeper and smaller fields, the difficulty of exploration grows. Not only are there greater costs associated with exploratory drilling, but as targets grow smaller and more distant from the surface, geological and geophysical information becomes harder, therefore more expensive to obtain.

The cost of replacing reserves on the intensive margin involves the costs associated with enhanced oil recovery (EOR). The study by Lewin and Associates of EOR potential of the United States indicated that the marginal cost of oil obtained by these technologies increases at an increasing rate.[52] Moreover, some of the methods are themselves energy intensive, or may involve use of materials which are themselves in short supply in the continental U.S. (like carbon dioxide). Reserve replacement cost, at either margin, represents an important area for future research. Determining the costs at the extensive margin is nearly impossible as the cost of exploration is very closely held proprietary information.

The resource augmenting nature of technologic advance over the period, however, was clear. Oil cost less to produce in 1972 than 1942 despite the fact that the fields were deeper, smaller and had lower productive capacity. Advances were made in drilling technology, production technology -- both working to reduce the cost of drilling, and improvement in geologic and geophysical reconaissance, enhanced information on the driller's target to reduce the likelihood of dry holes.

52. Lewin and Associates, op. cit.

As we now face declining quantitative and qualitative prospects for future discoveries, further resource augmentation through technological advance will rely heavily on the production techniques at the intensive margin. That is, extracting a greater quantity of the original oil in place in already discovered fields. Though drilling technology is important in this advanced phase of a field's production, the focus is shifted to changing the chemical and physical environment in the rock pores to liberate oil which remained after the natural energy of the reservoir was depleted.

This presents a new level of materials and energy intensity in oil production at a point in time when those goods themselves are more expensive than during the study period. Moreover, the continued reduction of residual oil saturation (the percent of oil left behind when the field is closed) beyond the point where primary and secondary recovery end, would logically seem to present input demands which would escalate exponentially. On a simple level, just the increase in the electrostatic charge between the oil and the rock which it coats, increases inversely with the square of the thickness of the oil film. Stripping away successive layers of this film can be accomplished only with very much higher quantities of energy delivered from the surface to the rock pores. There is no reason to believe that those processes will be cheaper on a unit basis than production of oil under primary and secondary recovery.

What does all of this mean for the value of unit cost as an indicator of scarcity? If increasing physical scarcity of oil means that annual production exceeds additions to reserves through new discoveries, then the turning point in unit cost clearly did not anticipate physical scarcity, which began to increase in the U.S. in 1970.[53] Our study showes costs continuing to decline after that point, through 1972. It must be noted though, that the inconsistency of the parameter estimate on year of discovery, which is expected to be the most sensitive parameter to this type of change, did begin slightly before the 1970 turning point in the reserves-to-production ratio. Accurately testing the significance of this sign, though, would require extending the analysis through the 1970s.

However, decomposing time changes in unit cost into the components related to deposit quality and technological advance did provide considerably more information that the simple time trend of costs. By measuring the importance of deposit quality in determining cost, and studying the variation in quality of new discoveries, unit cost gained a forward-looking component. Though the dominance of the old giant fields muted the effects of the trend in discoveries, the consequences of the eventual withdrawal of the giants from the resource base could be seen, even during a period of overall declining costs. This information on cost was a leading indicator of the turn which occurred in 1970, but it was buried in the time series and not communicated to the market.

Judged by the costs communicated to producers, and through them to consumers, unit cost fell during a period of expanding physical resources, which was a "correct" signal, but it failed to warn of the turning point. It is a mixed verdict, but the analysis has proved that studying unit cost carefully

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53. M.K. Hubbert, "Energy Resources," in National Academy of Sciences/National Resource Council, Resources and Man, (San Francisco: W.H. Freeman, 1969), pp. 157-242.

can provide information on future costs, even though costs observed in the market may not substantially lead to changes in the physical quantity of available resources. To this it can be added that the analysis has shown that in the case of petroleum, it is clear that the amount of physical resources in situ does not increase with declining deposit quality. This relationship has been suggested to exist in the case of some metals, but even if the empirical controversy there was resolved in favor of increasing tonnage with declining grade, it is not so with oil.[54] Higher cost/lower quality deposits are associated with reservoirs that are not only deeper, but contain less oil.

The corollary goal to empirical investigation of the cost of production, was to assess the utility of the engineering production/cost function. Because the prime objective was to study the relationship of physical and chemical laws at work in oil fields to the cost of production, the engineering specification was indispensible. A standard economic cost function, based for instance on a Cobb-Douglas production function, would have caught the decline in unit cost over time, but would have not produced information on the impact of the contemporaneous trends in the quality of newly discovered fields.

The two alternate specifications of cost embodied in Eqs. 4.5 and 4.6 both represent forms of the engineering production function, as the emphasis

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54. The relationship was first suggested for copper porpheries by S.G. Lasky in "The Concept of Ore Reserves," Mining and Metallurgy, vol. 26 (1945), pp. 471-474. The history of the empirical and theoretical controversy surrounding the question was reviewed by John H. DeYoung, Jr., "The Laskey Tonnage-Cummulative Grade Relationship - A Reexamination," Economic Geology, vol. 76 (1981), pp. 1067-1080.

has been shifted to physical parameters, minimizing the extent to which the models rely on assumptions about structure and performance in the input and product markets. The close performance between the two specifications indicates that the economic assumptions required for the derivation of Eq. 4.5 did not interfere with capturing the role of physical parameters in the production of crude oil and added information on the cost of capital that was lost in the "pure" engineering form. The engineering concept was found to provide very robust models in this investigation, supporting their special applicability to mineral extraction processes, which intuitively seem even more closely tied to the constraints of physical laws than, for instance, the pipeline transmission of natural gas, used by Chenery in his pioneering work.[55]

Though neither Eq. 4.5 or 4.6 represented a full specification of the determinants of production cost, physical parameters were found to be signficantly related to cost in all samples studied. This implies that those models of the production process which omit these considerations are misspecified. The effect of this is most likely to be bias in the estimates of those models which underevaluates the impact of declining deposit quality.

This agrees with the conclusion of Drew, Attanasi and Root that the omission of physical parameters in exploration models would also bias estimates toward a more optimistic result than the data warrent.[56] Empirical measurement of such biases, based on the models developed here

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55. Chenery, op cit.

56. Drew, Attanasi and Root, op. cit.

would necessitate resolving the question of the stability of the coefficient on year of discovery, which requires data through the seventies.

These findings all support the validity of this approach to analysis of extracting natural resources. The evidence on the influence of physical parameters on production costs and the question about the consistency of the coefficient on the year of discovery all warrent continued research on the topic using a data base that is broader in geographic scope and covers drilling and production records through the seventies. The substantive results on the time path of petroleum extraction costs shed some light on oil's physical and economic scarcity, but they have opened more doors than they have closed.

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Appendix 1

Table of Fields, Discovery and Estimated Ultimate Recovery

Field	Year of Discover or Initial Production	Estimated Ultimate Recovery
Adell, Northwest	1952	11.4
Adena	1953	77.5
Alameda	1958	10.3
Balko, South	1956	19.1
Baxterville	1944	288.5
Bay Springs	1965	35.5
Bayou Henry	1964	17.6
Belgian Anticline	1946	51.2
Benton	1941	40.2
Big Beaver	1954	13.1
Black Hollow	1953	10.6
Bolton	1954	20.8
Bonanza	1950	41.5
Bowes	1950	14.3
Boyd	1944	19.0
Bridger Lake	1966	73.8
Brookhaven	1943	130.1
Bryan	1958	28.4
Cache Creek	1946	26.0
Castaic Hills	1965	12.2
Cato	1966	20.5
Centerville	1940	8.8
Cha-Cha	1960	11.7
Chaveroo	1965	27.3
Cheviot Hills	1964	58.9
Clay City Consolidated	1942	338.0
Clear Creek	1958	10.7
Coalinga East Extension	1959	604.8
Cole Creek, South	1948	16.0
Corbin	1938	16.1
Cottonwood Creek	1953	55.0
Coyote Creek	1958	25.9
Cuyama, South	1949	253.5
Cymric (McKittrick Front Area)	1965	136.0
Cypress Creek, South	1969	12.8
Dale Consolidated	1940	101.0
Dead Horse Creek	1957	20.6
Del Valle	1940	41.1
Diamond	1957	14.7
Dillinger Ranch	1964	11.5
Divide Consolidated	1949	11.9
Duvall Ranch	1964	14.5
El Mar	1959	6.0
Eldorado Consolidated	1941	12.7
Elk Basin, South	1945	23.6
Eubank	1958	16.2

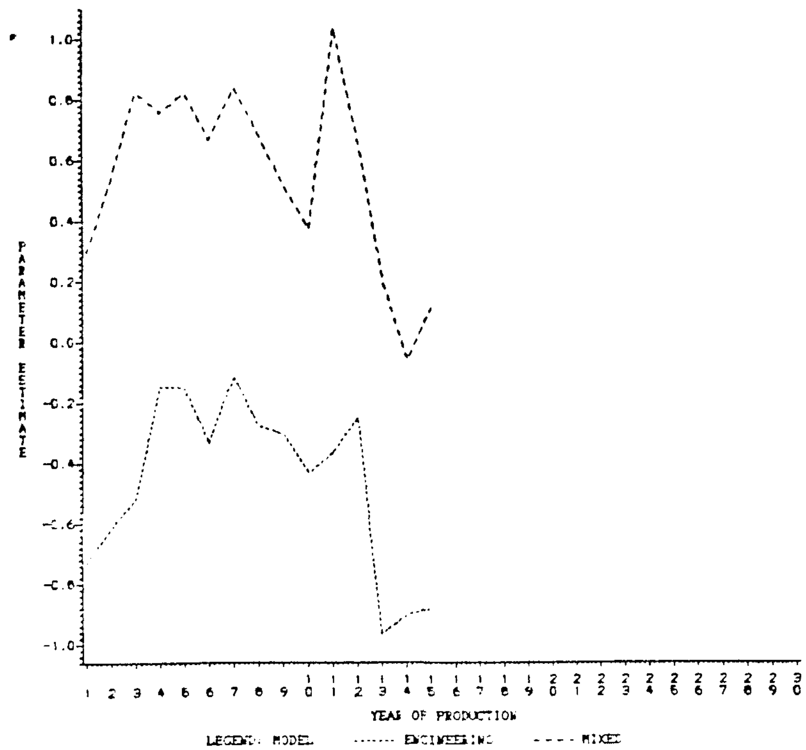
Eucutta, East	1959	54.3
Fairview	1965	8.1
Fayette	1945	10.1
Fiddler Creek	1948	22.9
Fillmore	1954	15.6
Flat Lake	1964	16.8
Flodine Park	1959	3.7
Fordoche	1948	32.1
Fourbear	1956	21.3
Gas City	1955	9.5
Gas Draw	1968	28.7
Gebo	1943	31.5
Gilbertown	1958	10.8
Glendive	1952	13.7
Golden Eagle	1921	13.9
Golden Trend	1954	613.0
Goldengate Consolidated	1939	19.0
Graylin, Northwest	1951	14.9
Greater Aneth	1956	434.0
Grieve	1954	38.3
Guadalupe	1948	40.9
Hanston-Oppy	1961	9.0
Honor Rancho	1950	13.4
House Creek	1968	20.6
Inman, East Consolidated	1940	24.6
Interstate	1953	27.6
Iola Consolidated	1939	17.4
Irvington	1940	10.2
Ismay (Flodine)	1956	47.9
John Creek	1953	8.3
Johnsonville Consolidated	1940	55.3
Kitty	1965	27.2
Las Cienegas	1960	68.7
Lisbon *	1960	176.9
Little Beaver	1952	13.0
Little Beaver, East	1954	6.2
Little Buffalo Basin	1914	154.9
Little Creek	1958	51.0
Los Angeles Downtown	1969	18.0
Lovington, East	1951	67.0
Manderson	1951	9.0
Mason, North	1954	4.6
Meadow Creek	1958	44.9
Meadow Creek, North	1949	18.4
Merit	1959	8.2
Monarch	1958	5.4
Montalvo, West	1947	54.0
Moore, West	1943	39.4
Mt. Vernon	1952	9.7
Murphy Dome	1949	38.0
Mush Creek	1943	13.3
Nancy, East	1968	10.3
North Fork	1951	21.5
Norwich, East	1942	15.9

Oakridge	1952	16.5
Overton	1951	10.6
Ovett	1948	10.0
Pachuta Creek	1968	59.7
Paddock	1945	29.2
Peters	1955	9.1
Pierce	1955	10.8
Pine	1951	107.3
Pleasant Prairie	1954	20.4
Plum Bush Creek	1954	19.0
Poison Spider, West	1948	14.5
Pollard	1958	11.5
Pool Creek	1961	10.6
Poplar, East	1952	46.6
Postle	1958	128.1
Pyramid Hills	1958	90.1
Quitman Bayou	1963	32.7
Raleigh	1957	41.8
Reagan	1947	7.7
Recluse	1967	33.0
Red Wash	1958	101.2
Ringwood	1945	159.8
Rose City	1942	11.2
Rosedale Ranch	1945	15.9
Rozet	1959	23.9
Sage Creek	1947	20.6
Sage Spring Creek	1949	11.5
Salt Creek, East	1951	13.2
Sansinena	1940	65.7
Santa Susana	1963	14.6
Saunders	1950	30.5
Sawtelle	1965	13.8
Seiling, Northeast	1952	4.9
Singleton	1958	11.1
Skull Creek	1946	12.0
Sleepy Hollow	1960	47.5
Soso	1945	84.1
Square Lake	1941	29.7
St. Helen	1950	10.3
Steamboat Butte	1943	88.5
Stensvad	1958	10.1
Storms Consolidated	1953	24.6
Summerland	1961	17.8
Sussex	1948	68.7
Sussex, West	1951	21.3
Sweet Lake	1948	36.9
Tallahala Creek	1966	21.5
Teapot, East	1951	54.0
Timber Creek	1958	16.0
Tinsley	1951	218.5
Tobac	1964	11.6
Unger	1955	8.2
Upper Valley	1964	151.7
Ute	1967	14.0

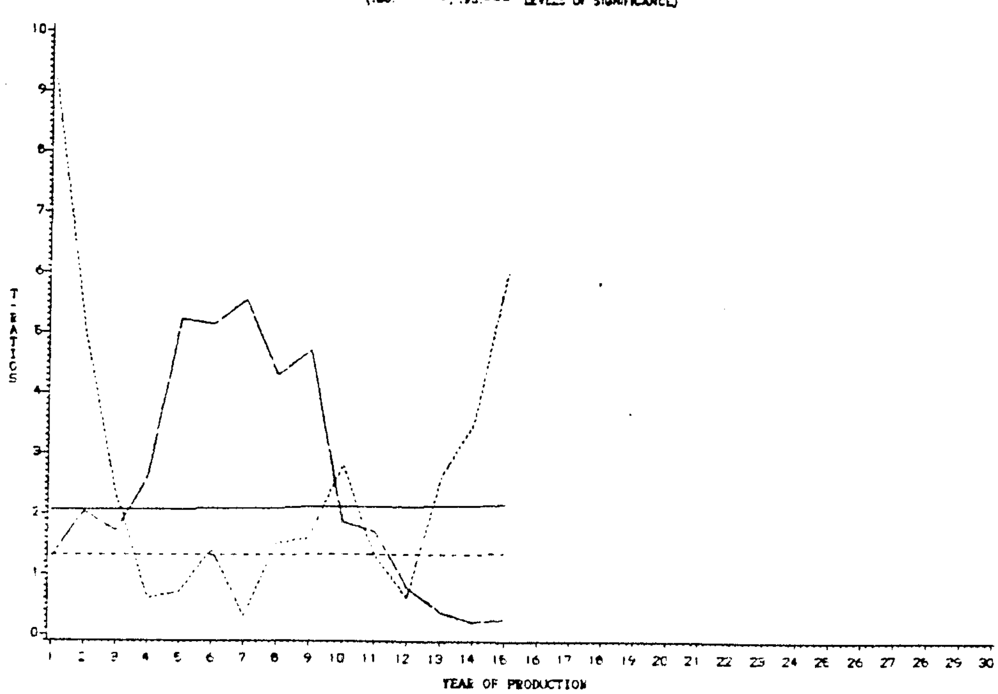
Vada	1966	70.0
Yenter	1950	14.1

Appendix 2

LOG OF PRODUCTION
(TOP GULF SAMPLE)

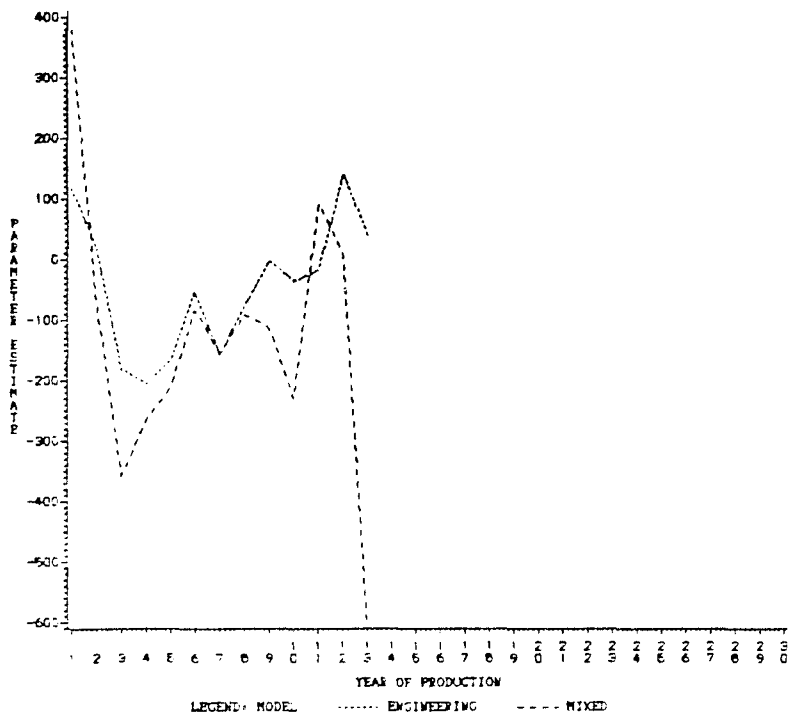


LOG OF PRODUCTION – T RATIOS
(.90:– – –, .95:––– LEVELS OF SIGNIFICANCE)

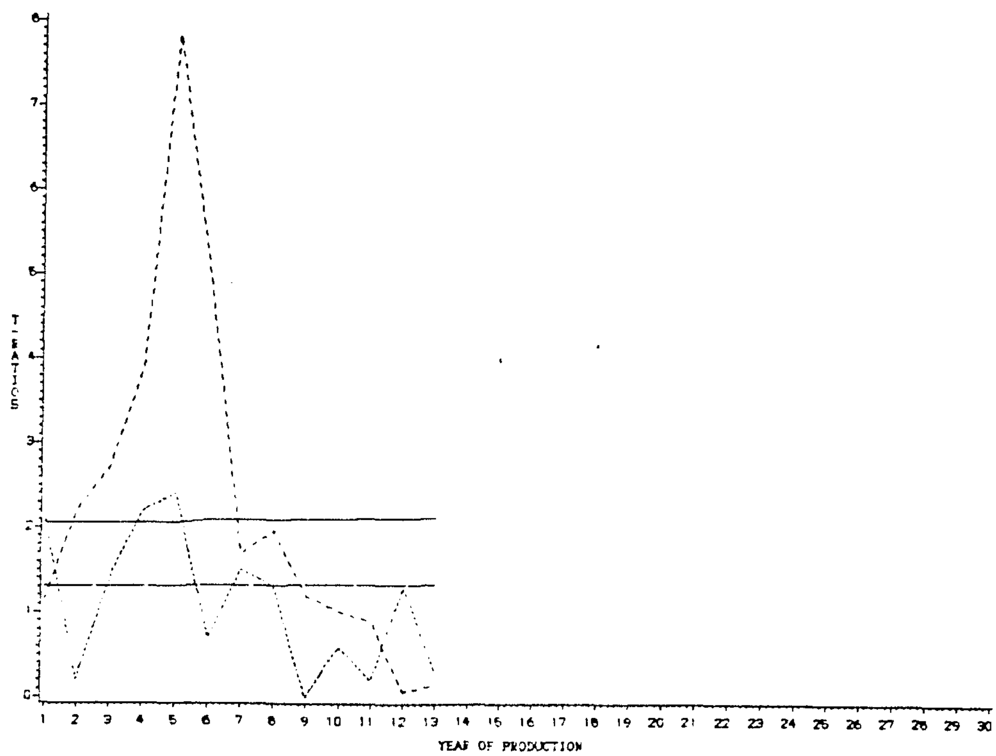


Figures A.1a and A.1b

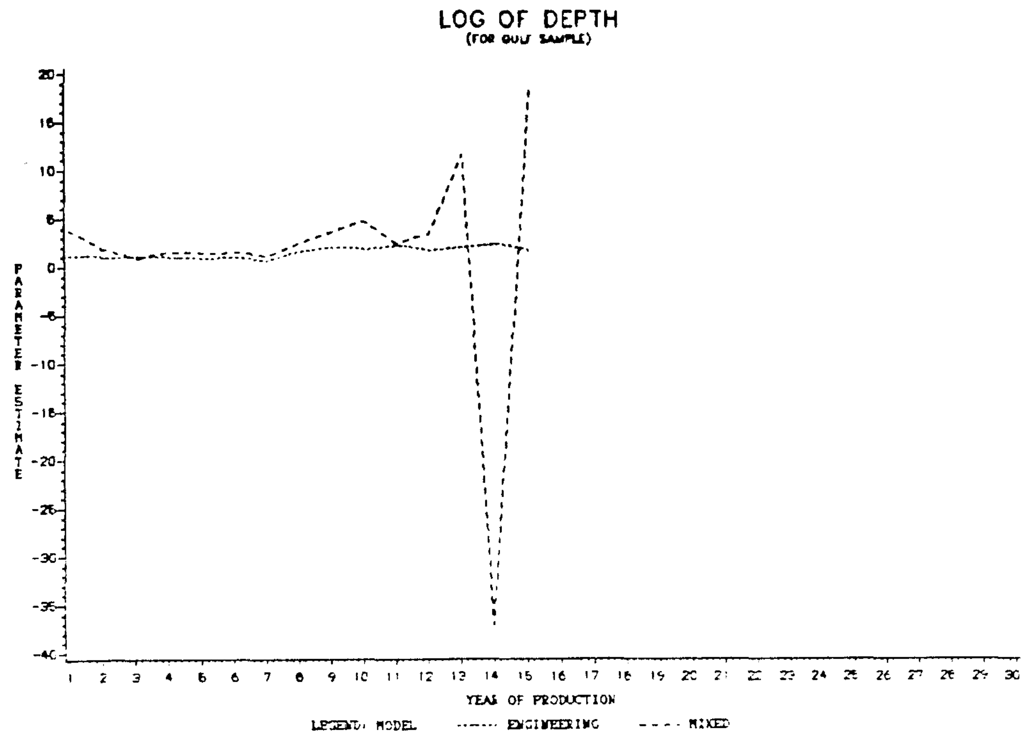
LOG OF DISCOVERY YEAR
(FOR GULF SAMPLE)

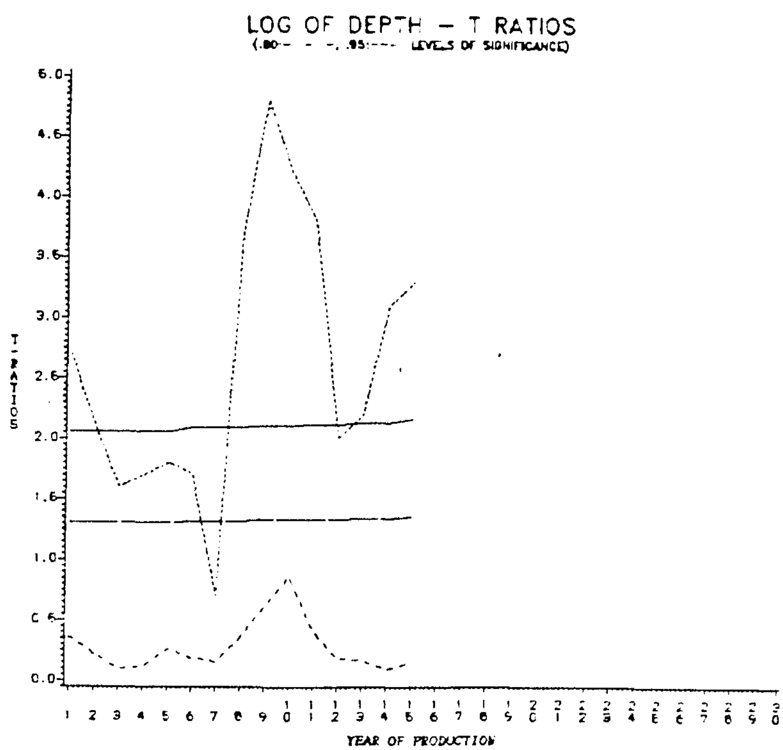


LOG OF DISCOVERY YEAR – T RATIOS

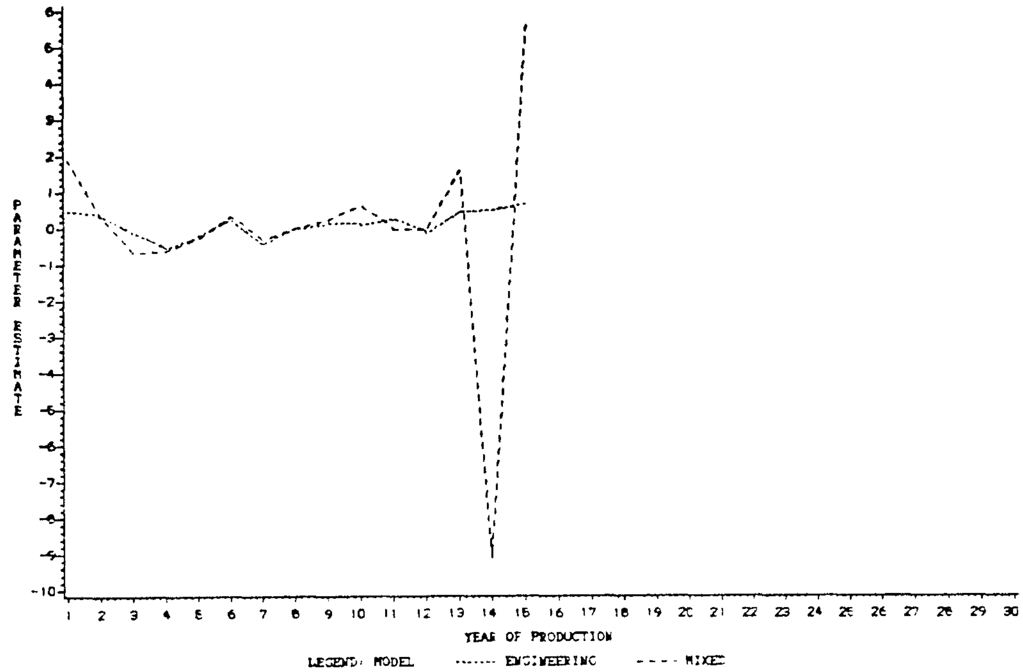


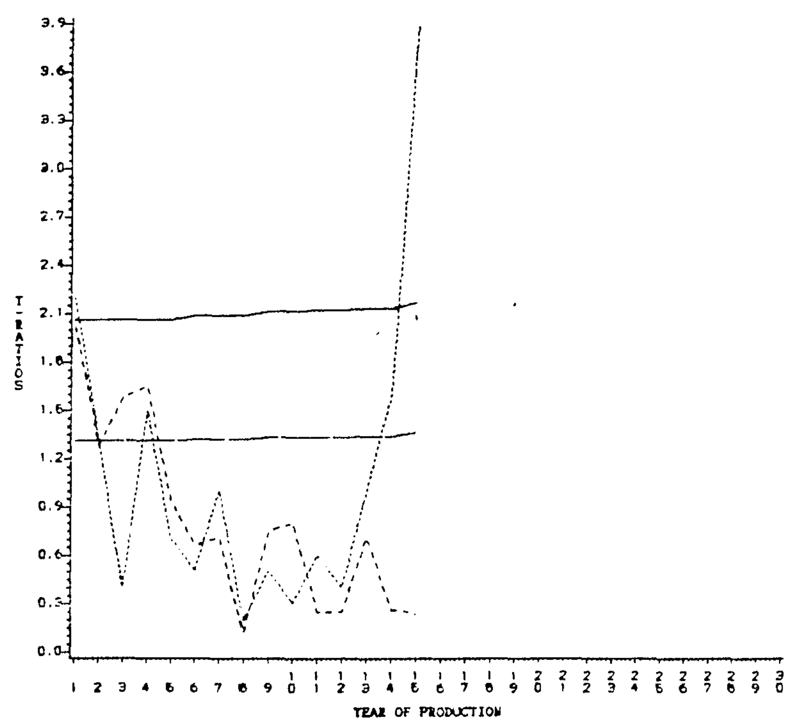
Figures A.2a and A.2b



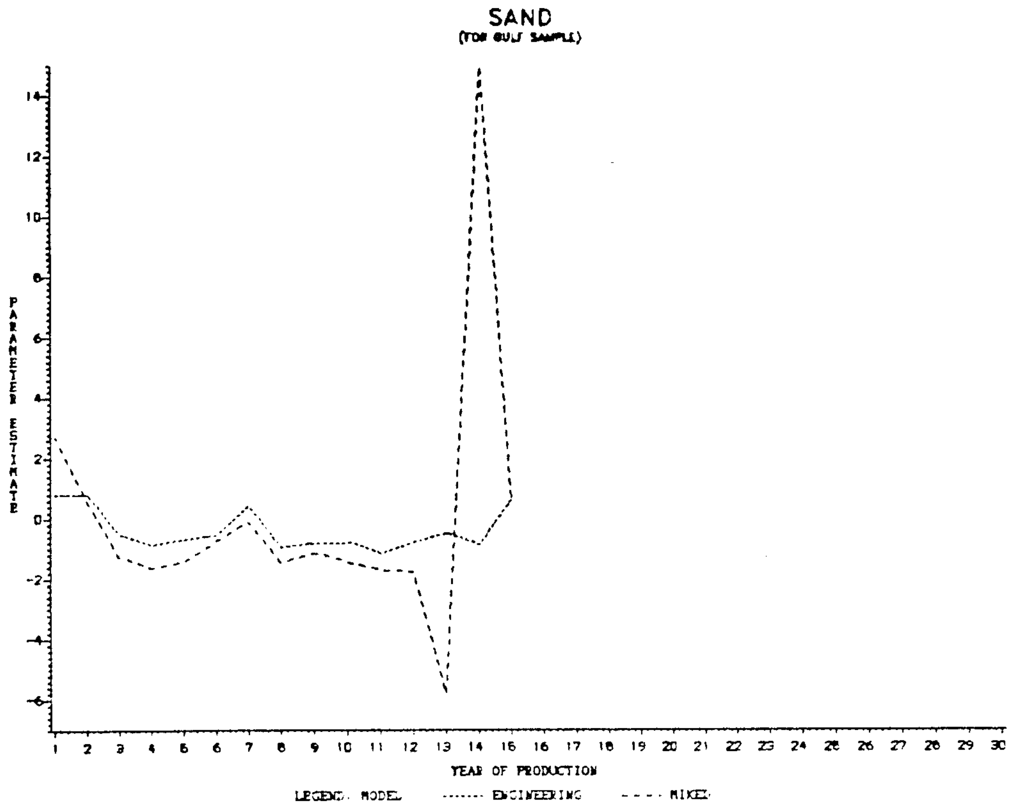


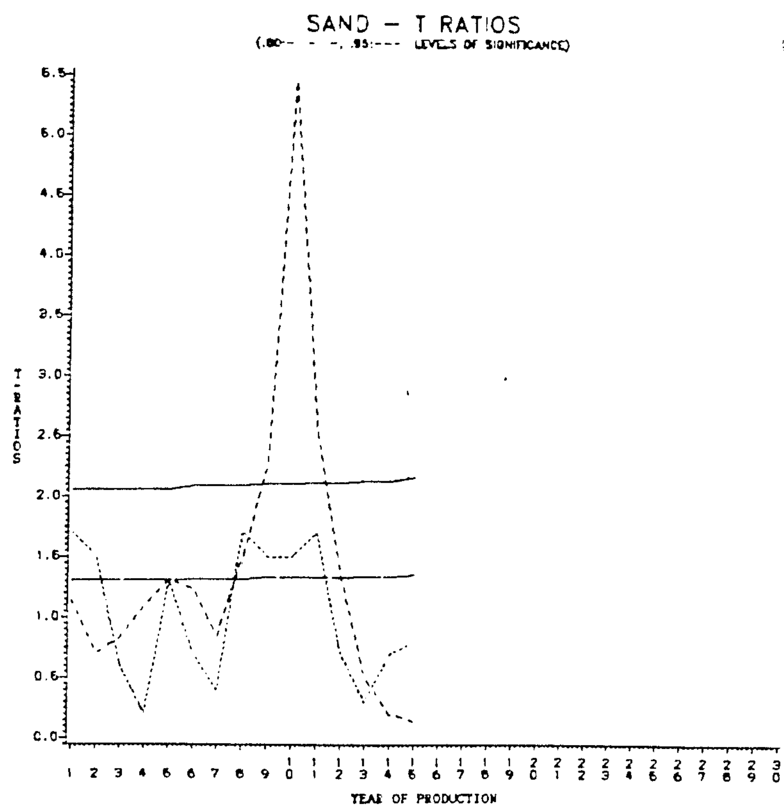
Figures A.3a and A.3b





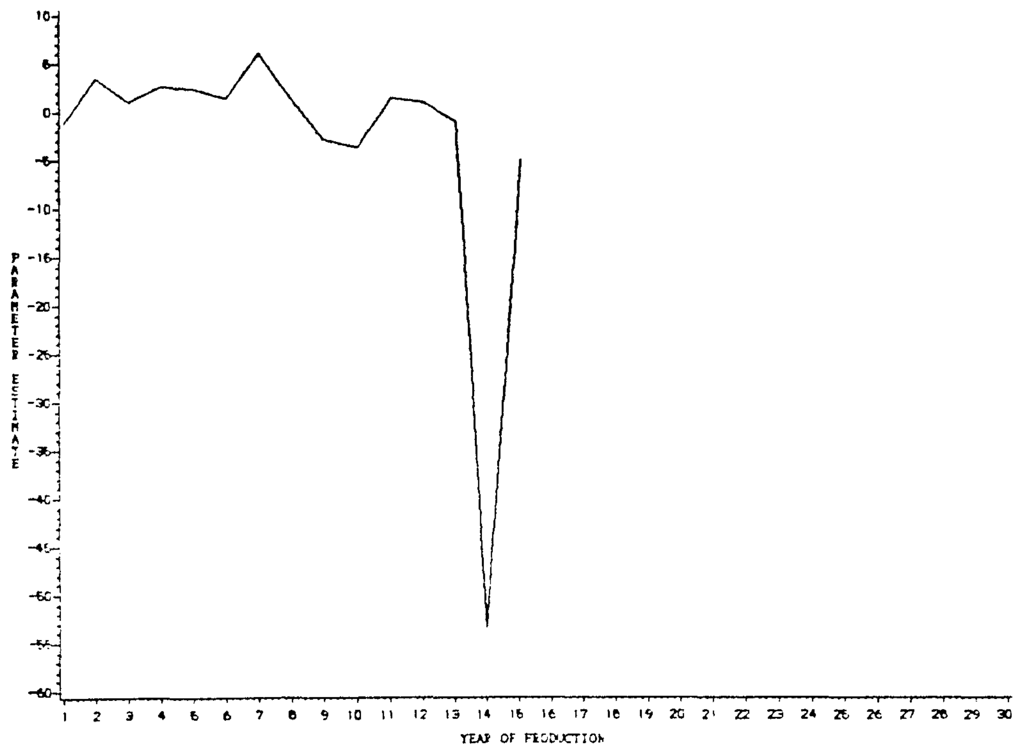
Figures A.4a and A.4b



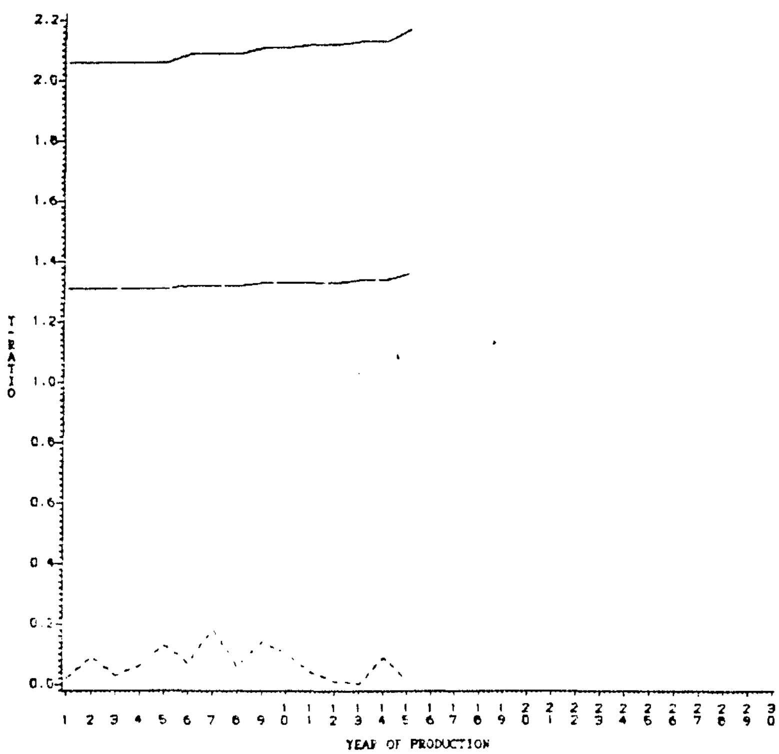


Figures A.5a and A.5b

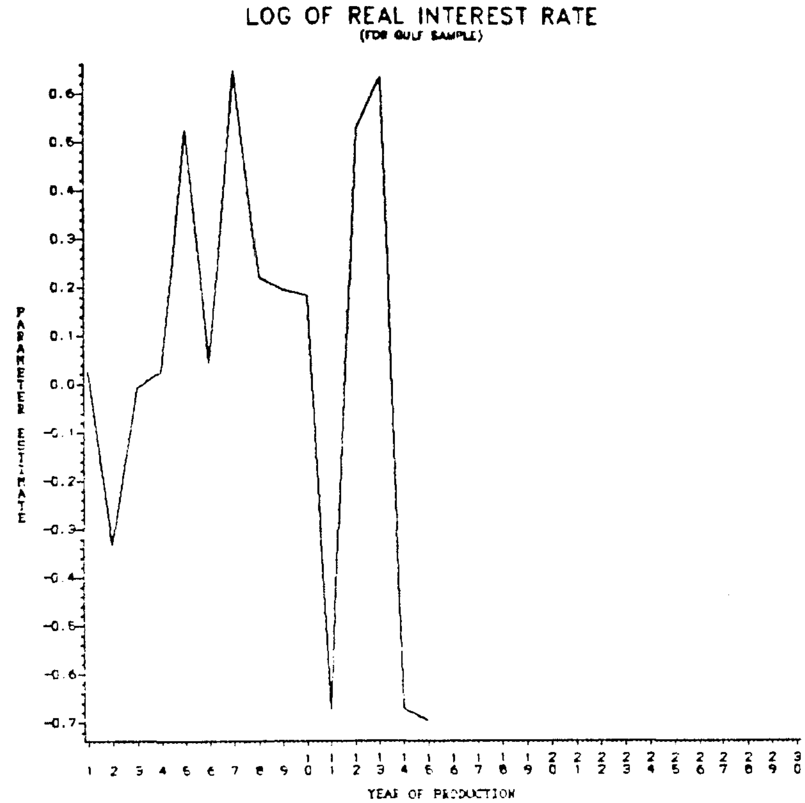
LOG OF LABOR - CAPITAL RATIO
(FOR GULF SAMPLE)

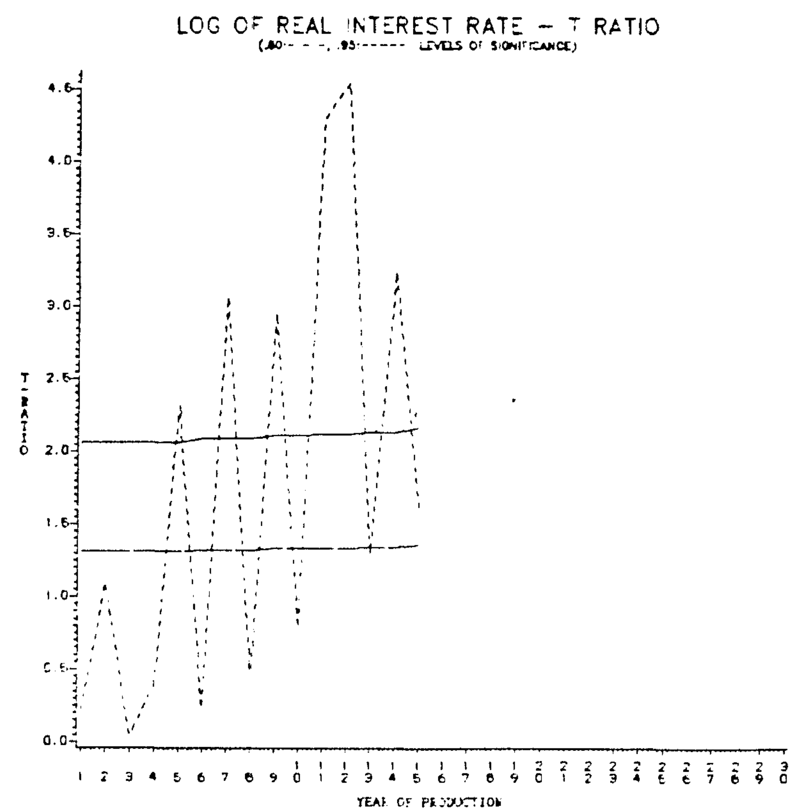


LOG OF LABOR - CAPITAL RATIO - T RATIO
(.80: - - -, .95: ------ LEVELS OF SIGNIFICANCE)



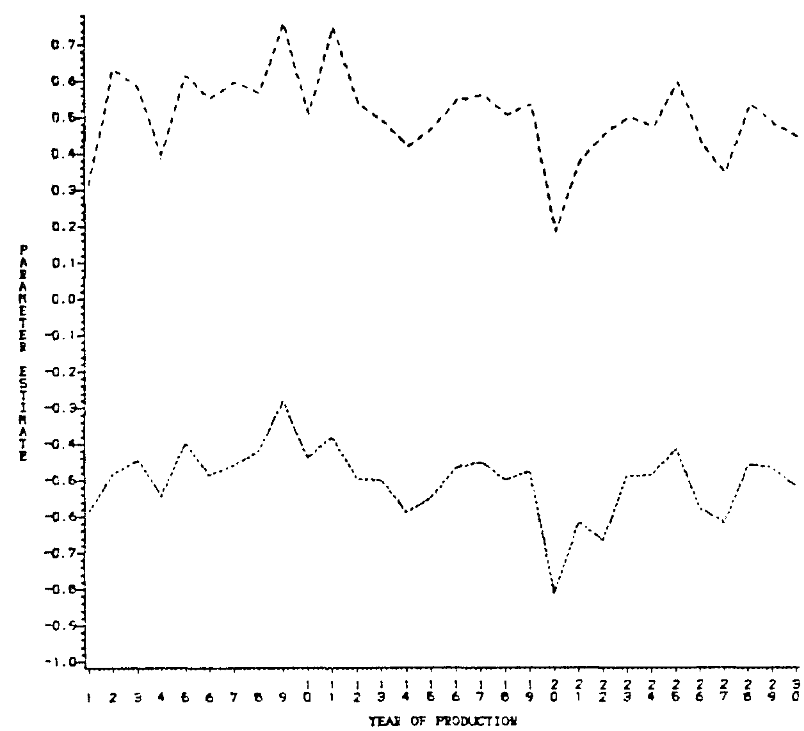
Figures A.6a and A.6b



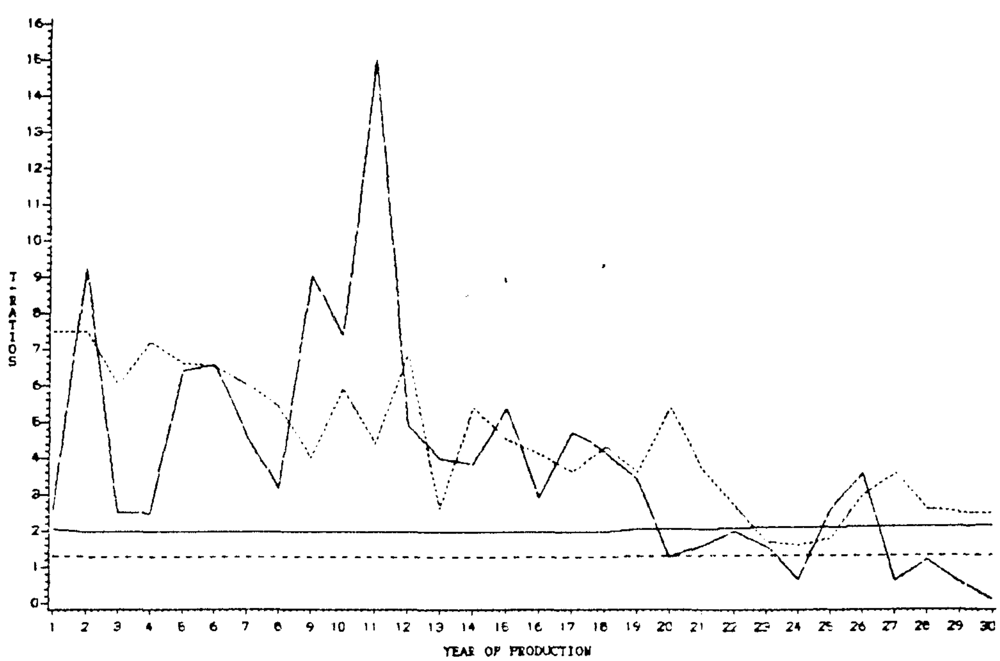


Figures A.7a and A.7b

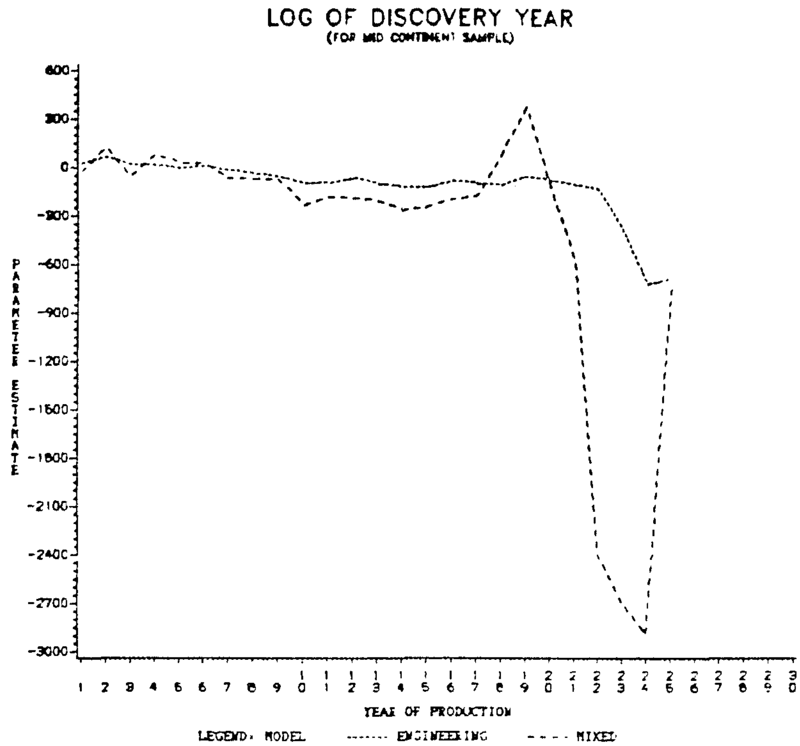
LOG OF PRODUCTION
(FOR MID CONTINENT SAMPLE)

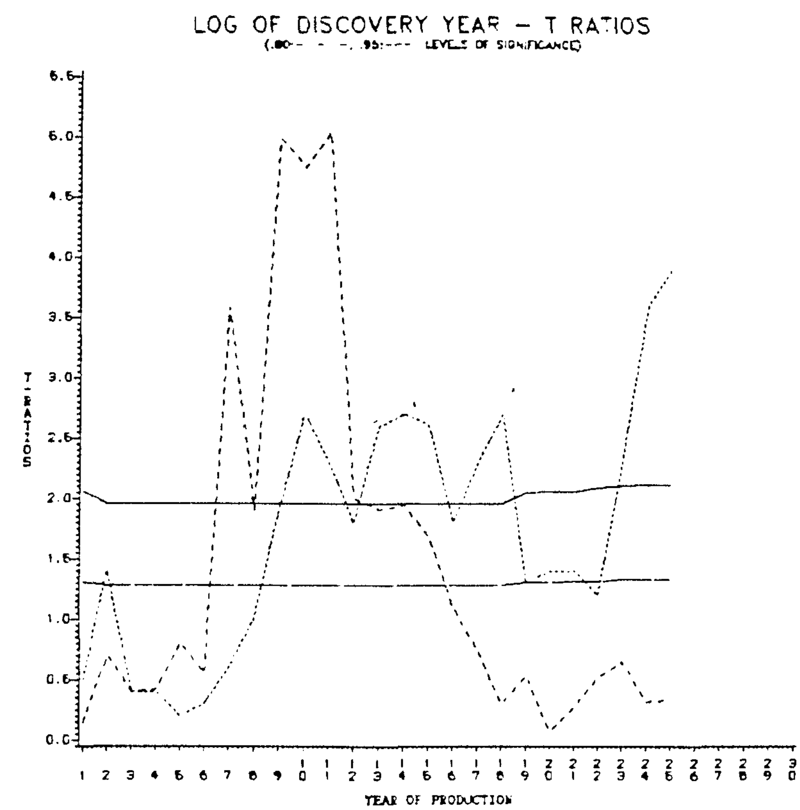


LOG OF PRODUCTION – T RATIOS
(.80:– – –, .95:---- LEVELS OF SIGNIFICANCE)



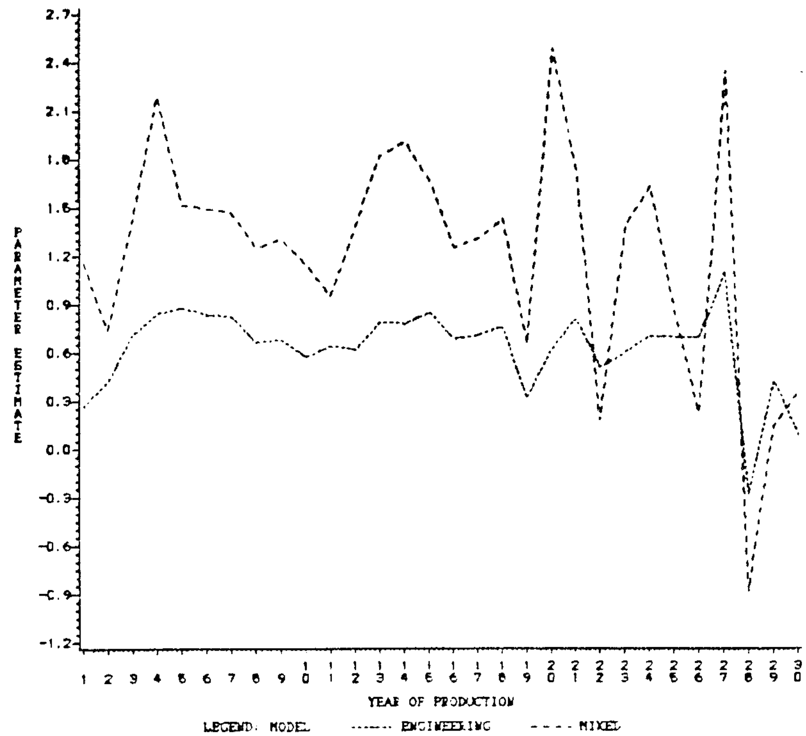
Figures A.8a and A.8b



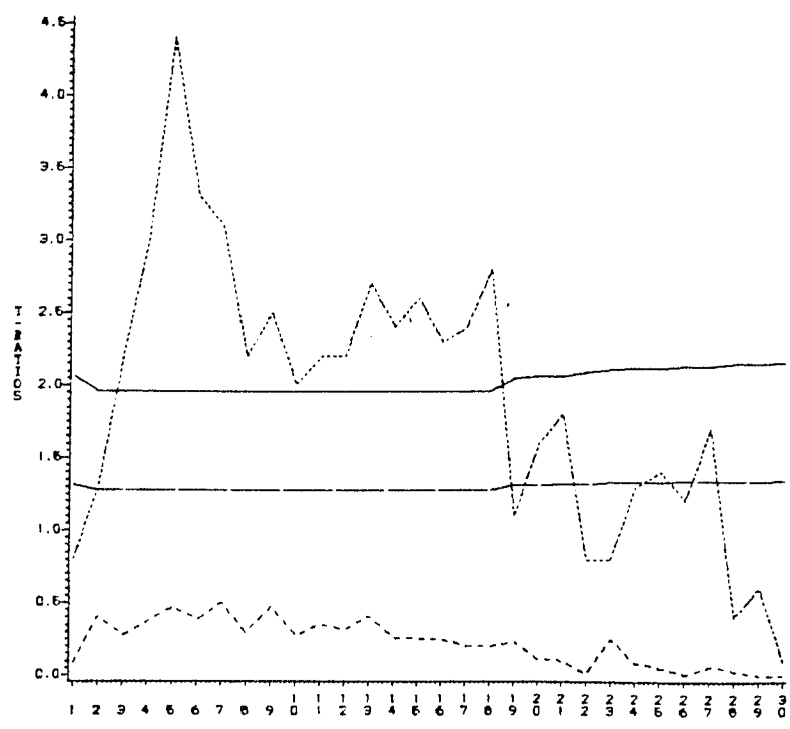


Figures A.9a and A.9b

LOG OF DEPTH
(FOR MID CONTINENT SAMPLE)

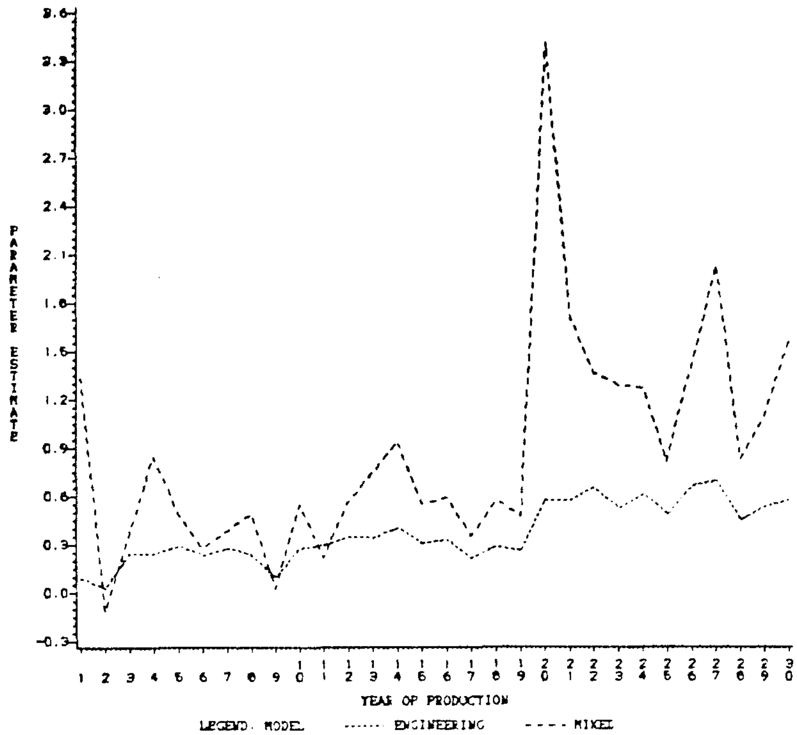


LOG OF DEPTH – T RATIOS
(.80:- - -, .95:--- LEVELS OF SIGNIFICANCE)

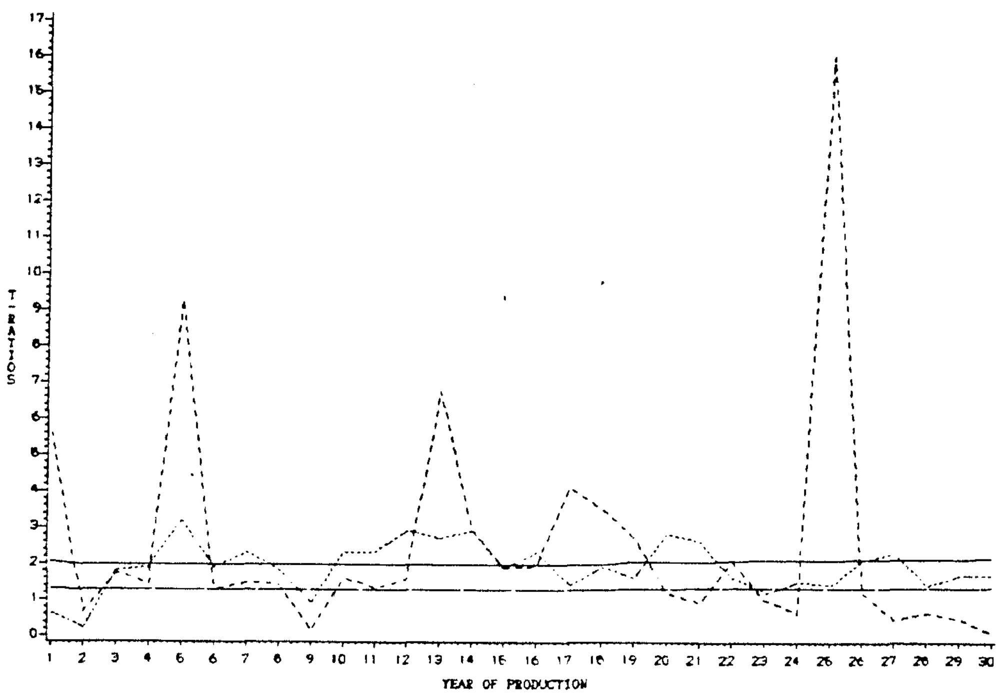


Figures A.10a and A.10b

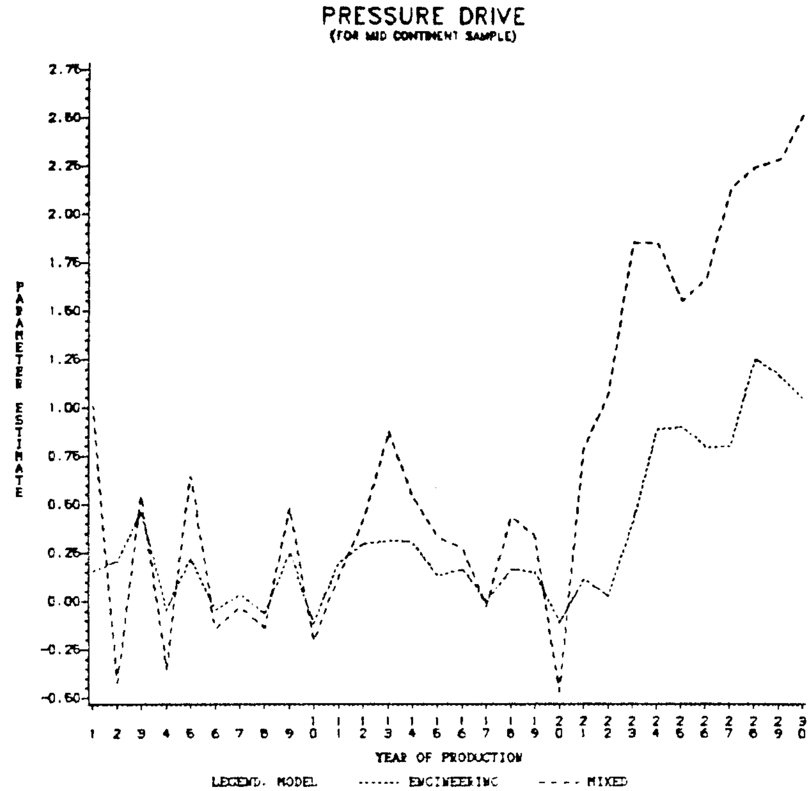
LOG OF SURFACE
(FOR MID CONTINENT SAMPLE)

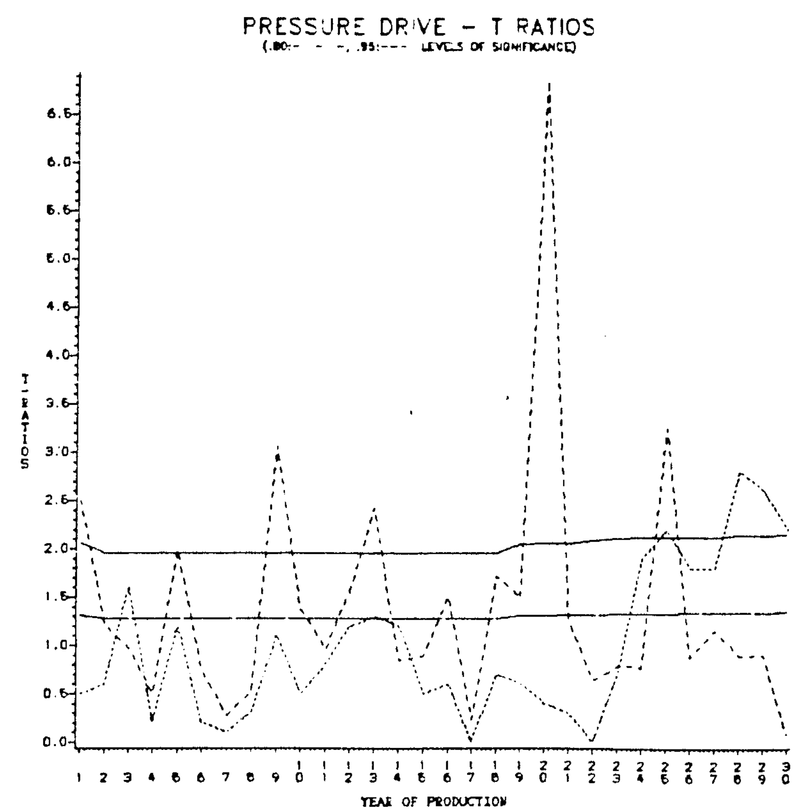


LOG OF SURFACE – T RATIOS
(.80:- - -, .95:--- LEVELS OF SIGNIFICANCE)

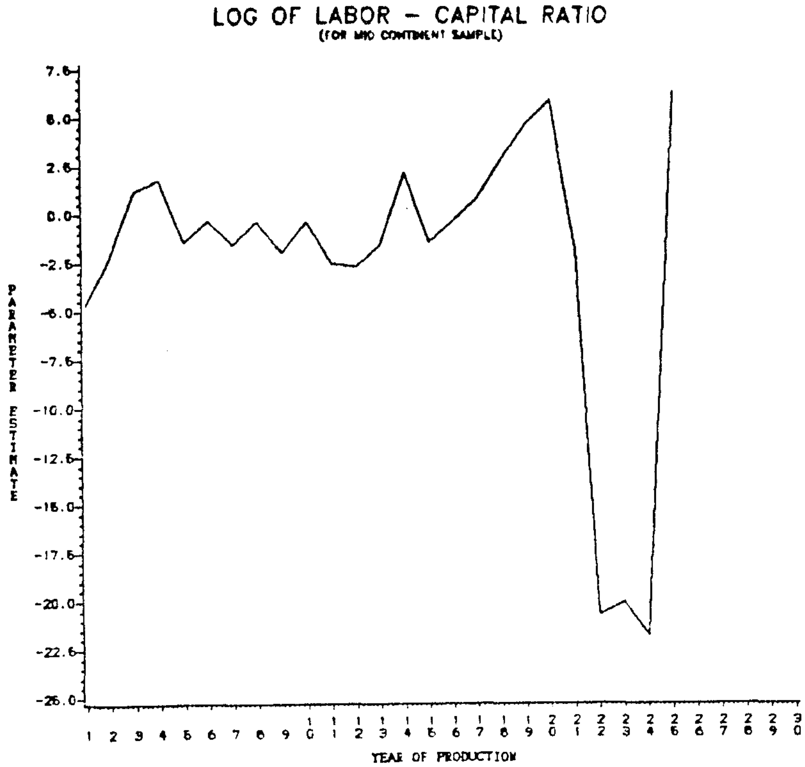


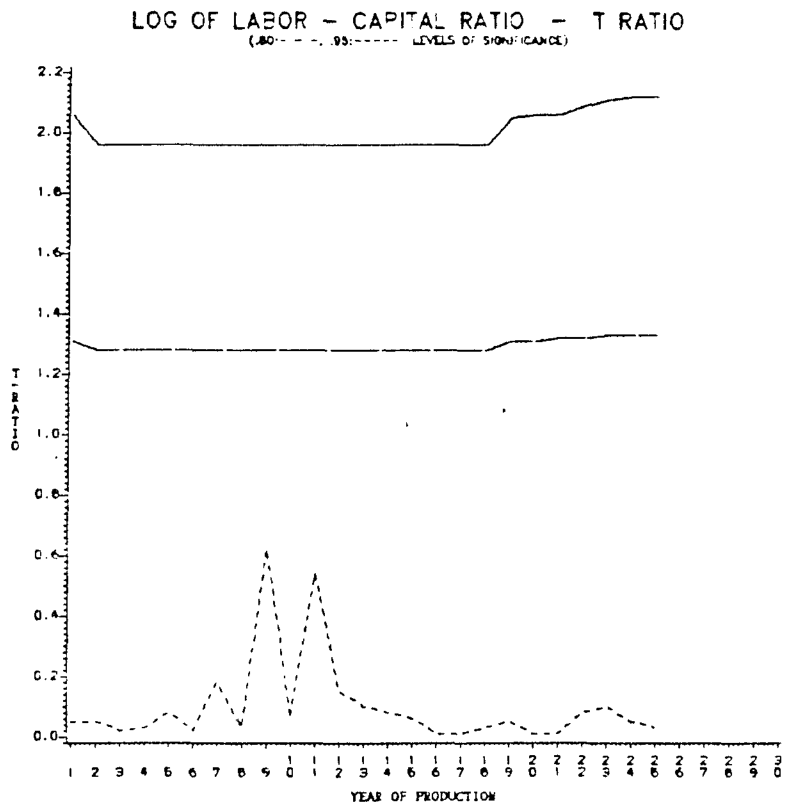
Figures A.11a and A.11b



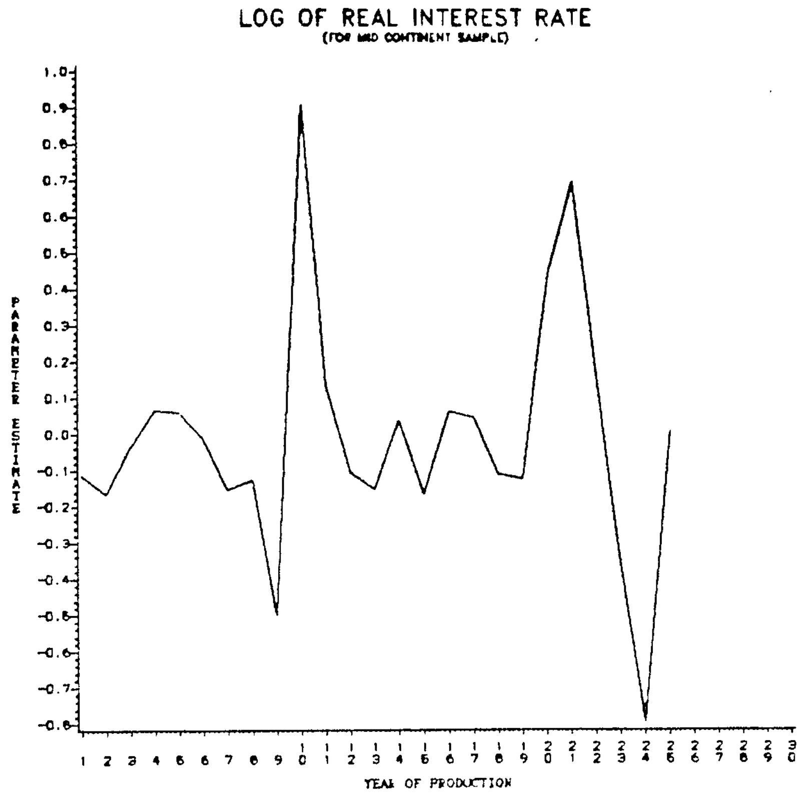


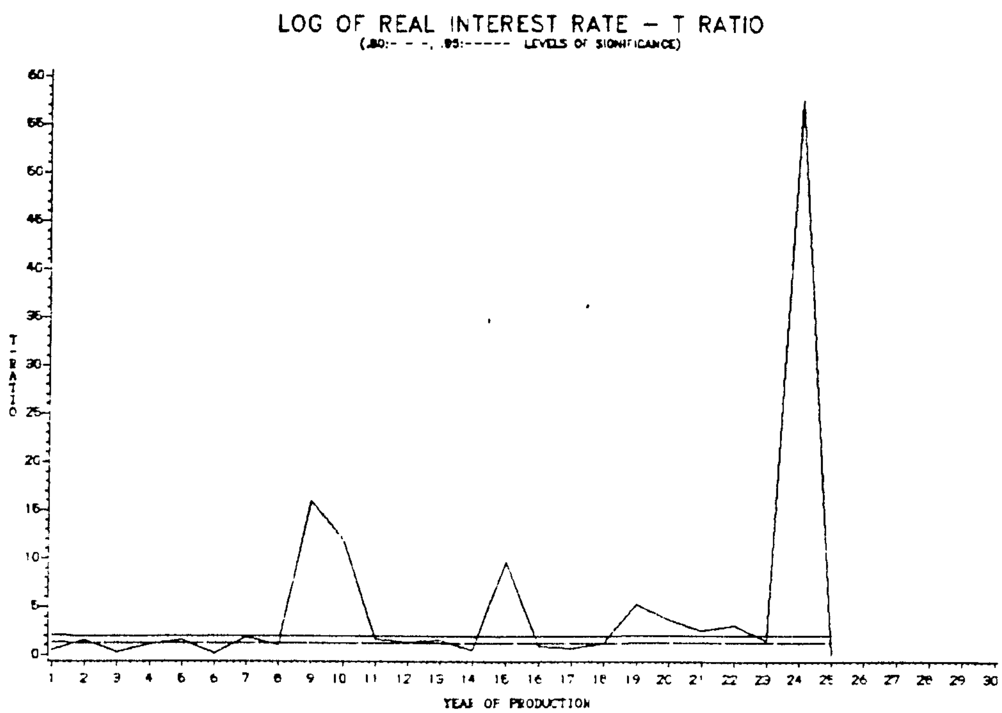
Figures A.12a and A.12b



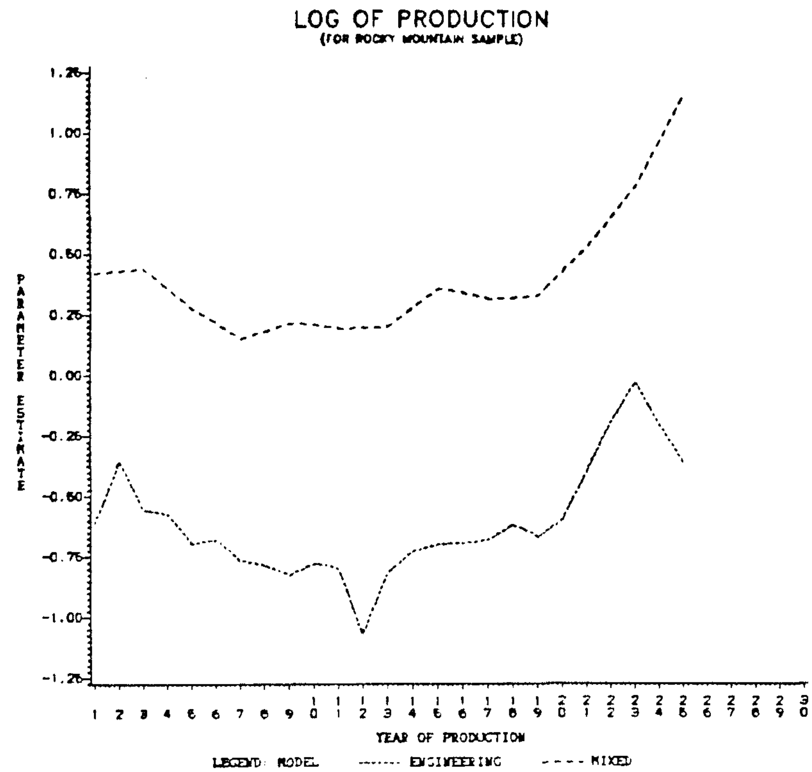


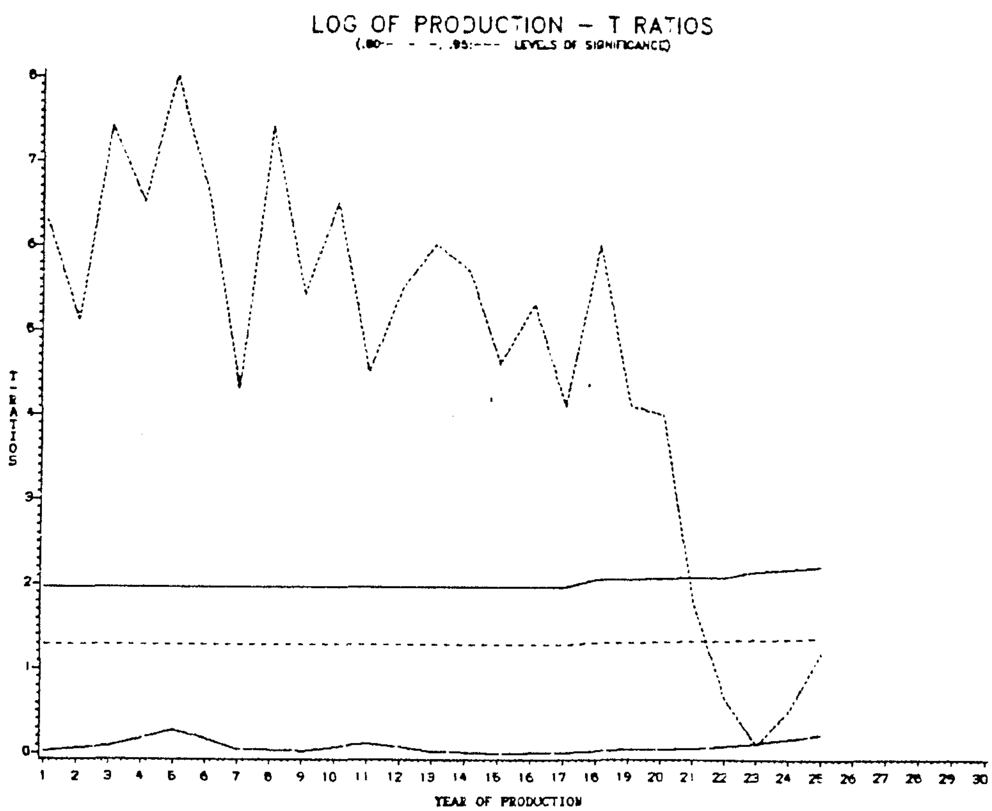
Figures A.13a and A.13b



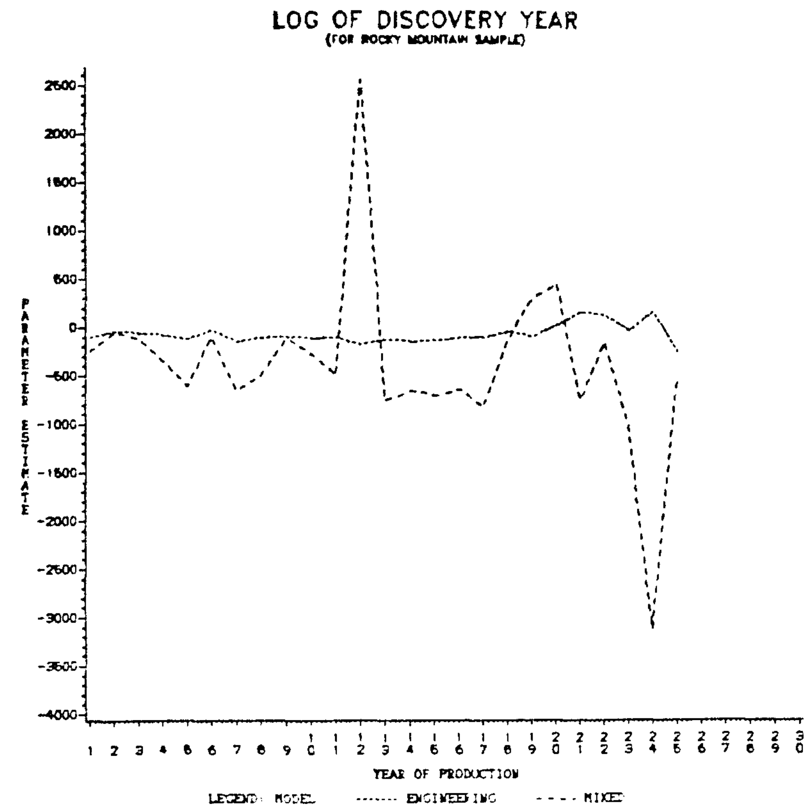


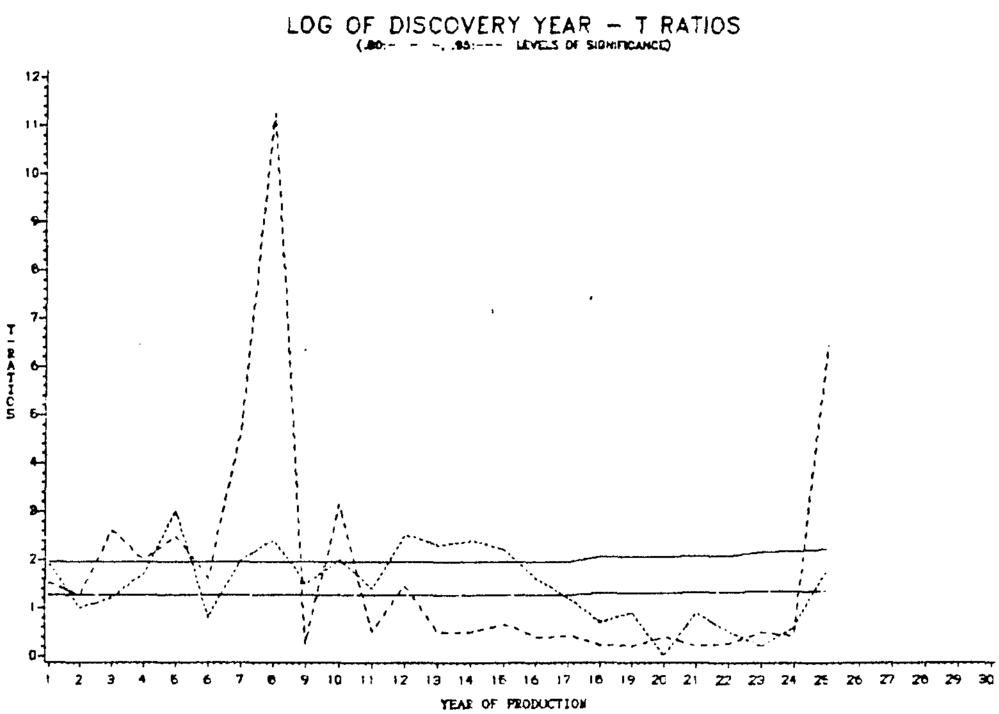
Figures A.14a and A.14b



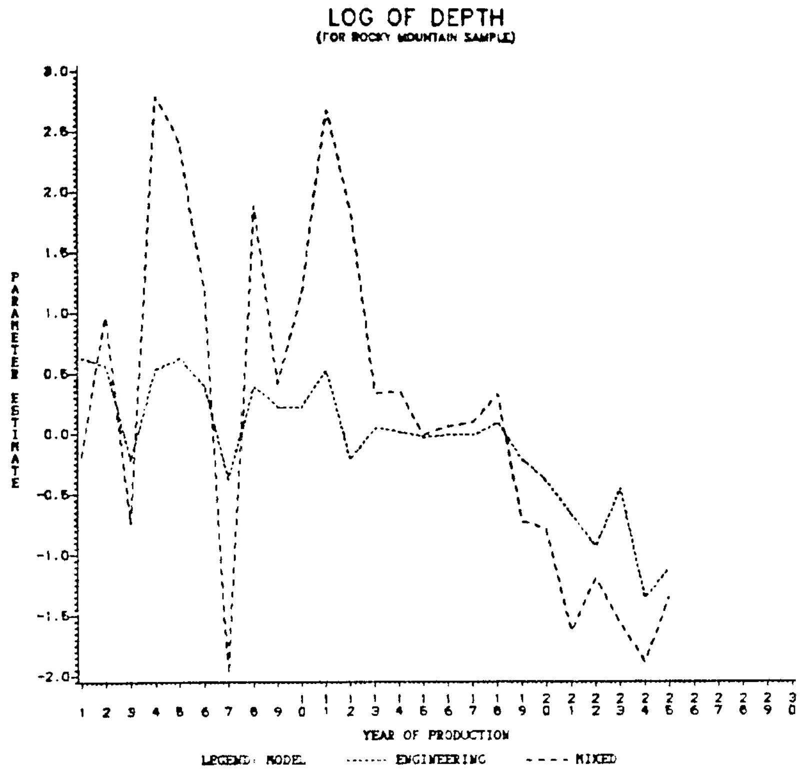


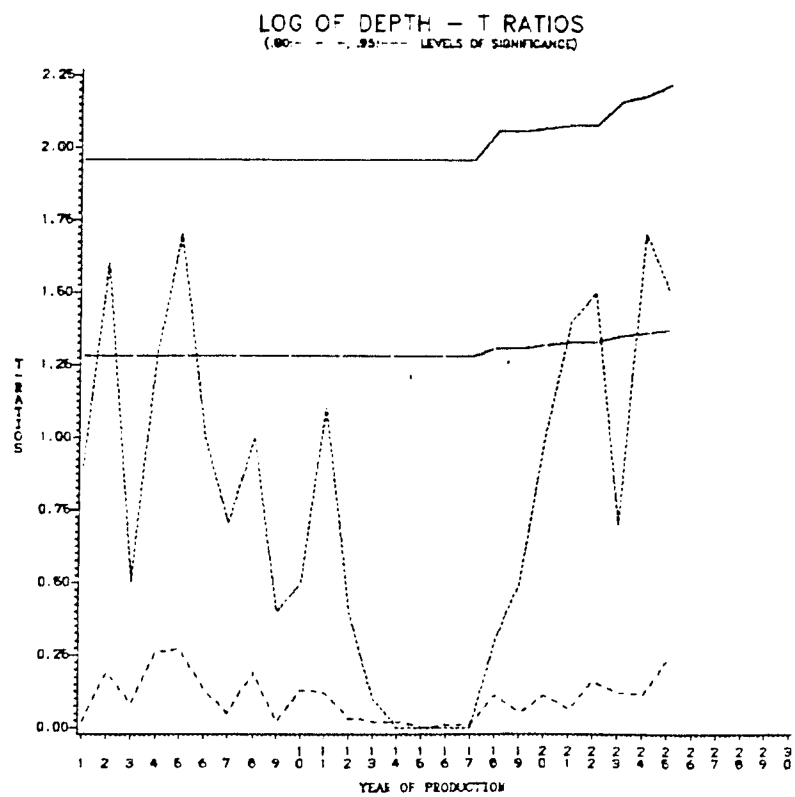
Figures A.15a and A.15b





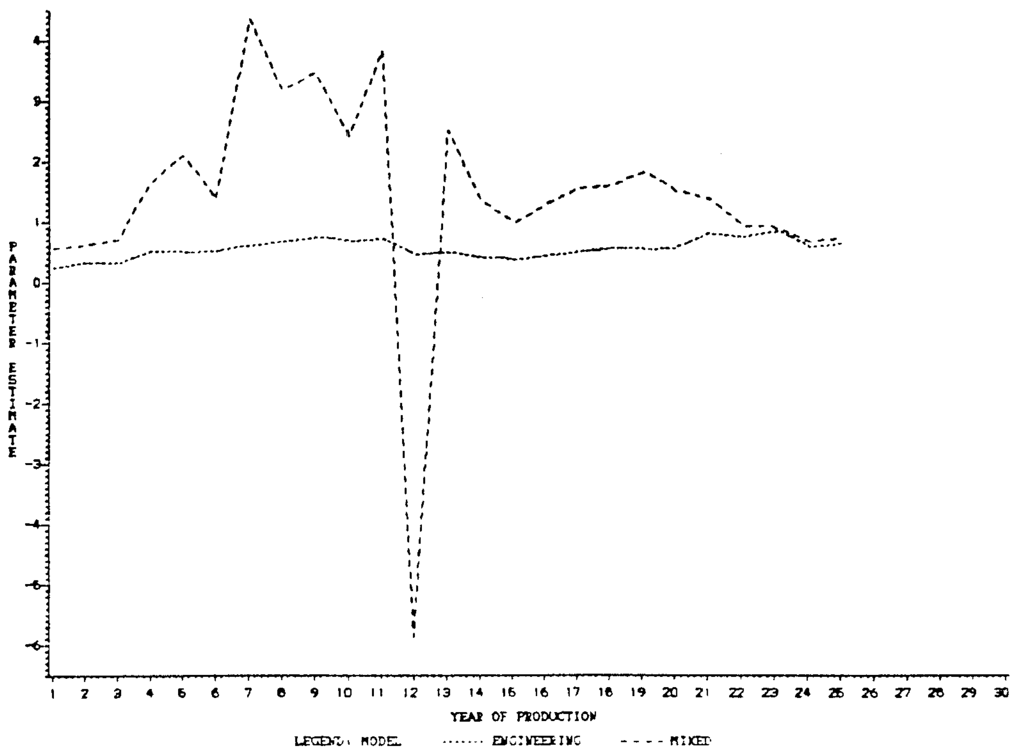
Figures A.16a and A.16b



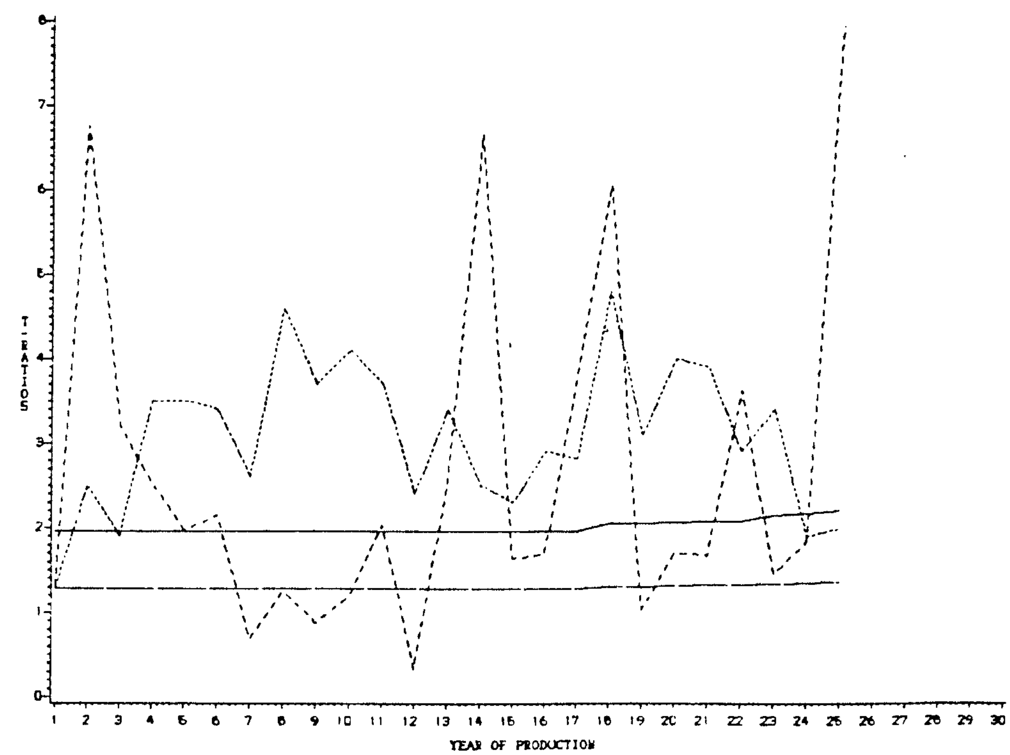


Figures A.17a and A.17b

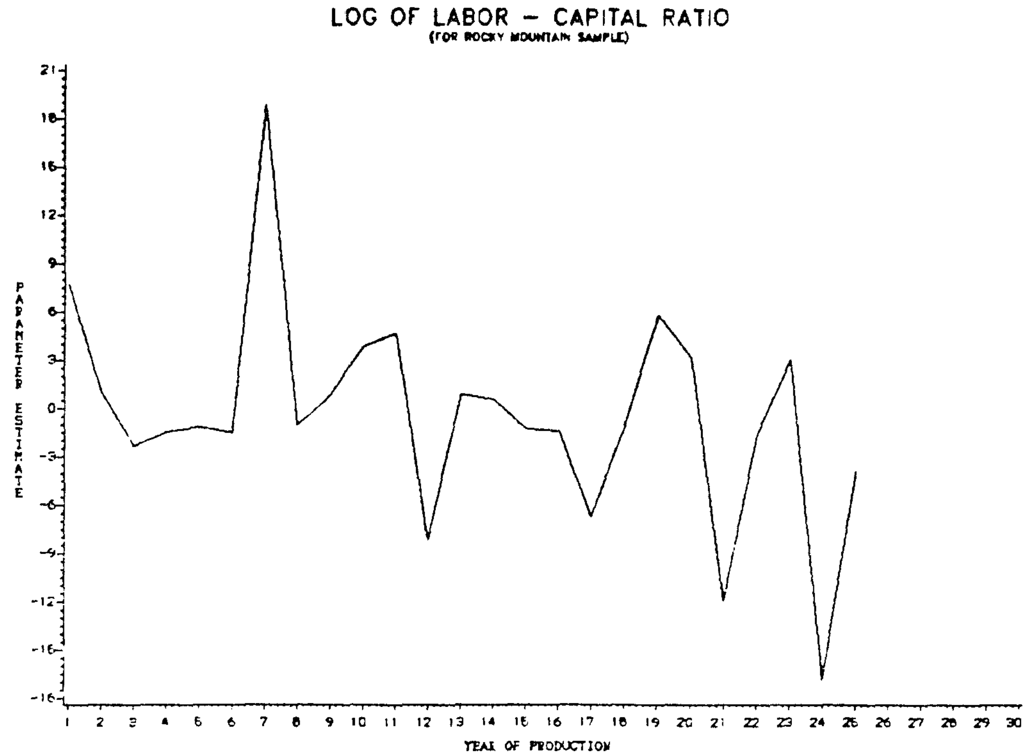
LOG OF SURFACE
(FOR ROCKY MOUNTAIN SAMPLE)

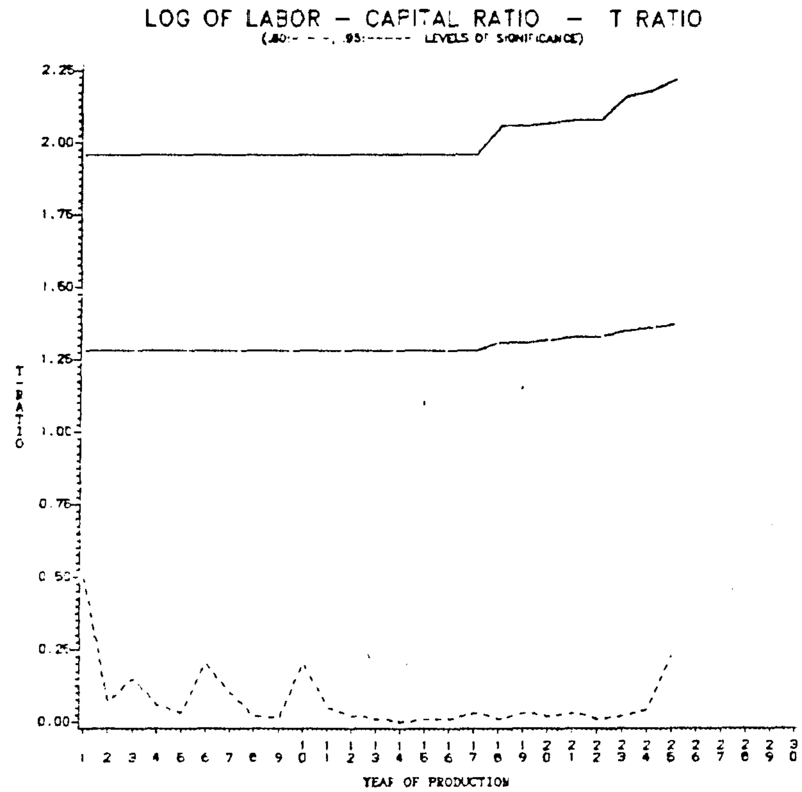


LOG OF SURFACE – T RATIOS
(.90:– – –, .95:––– LEVELS OF SIGNIFICANCE)

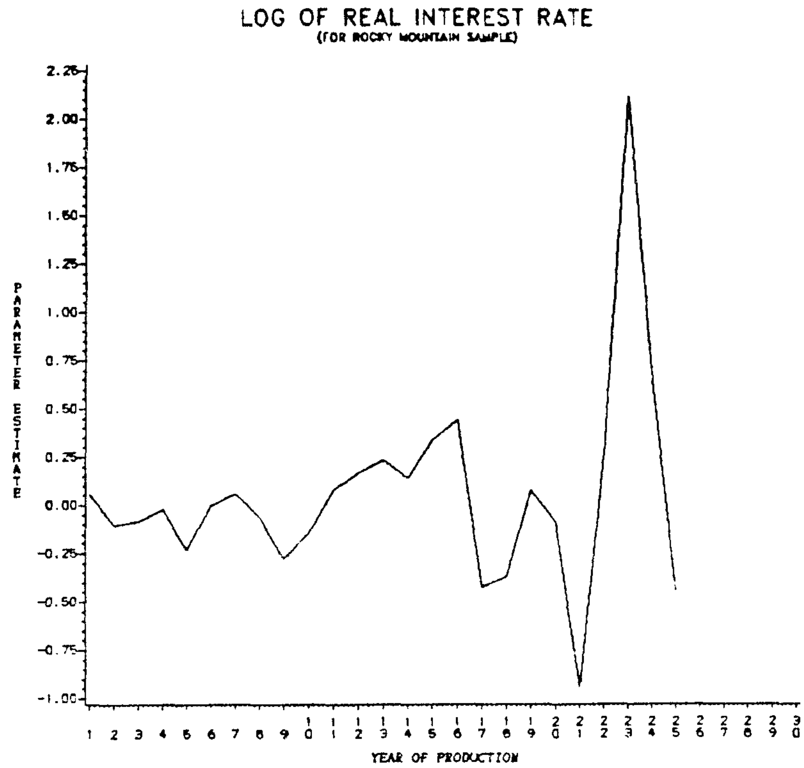


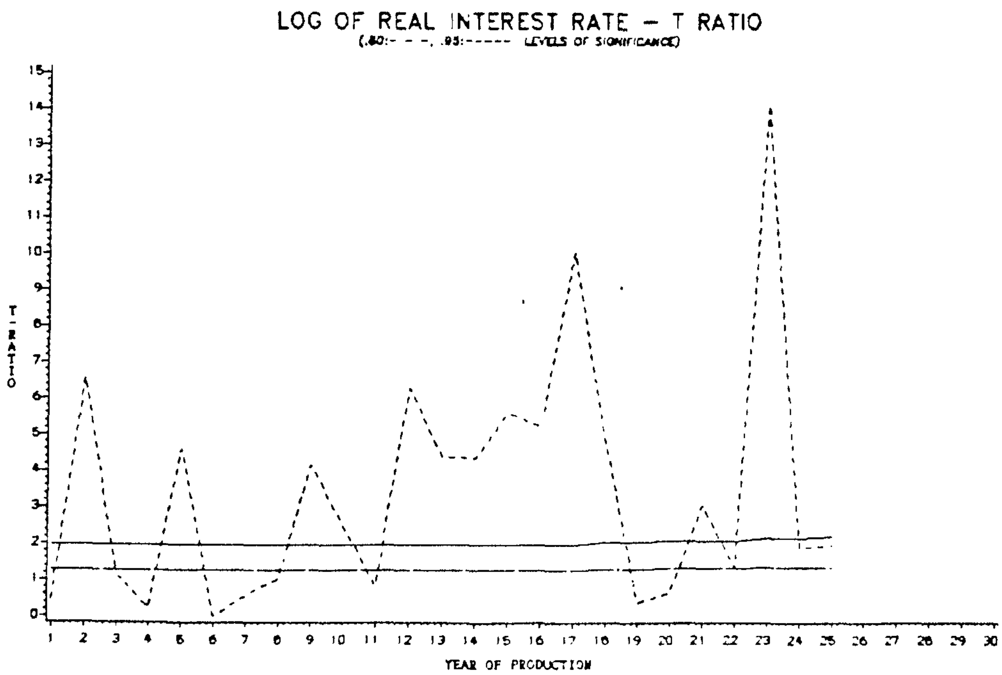
Figures A.18a and A.18b





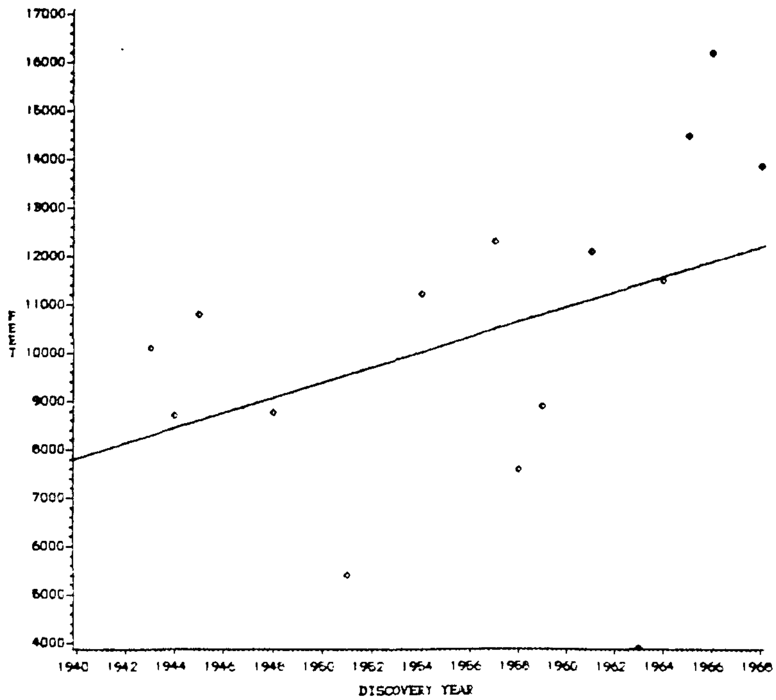
Figures A.19a and A.19b



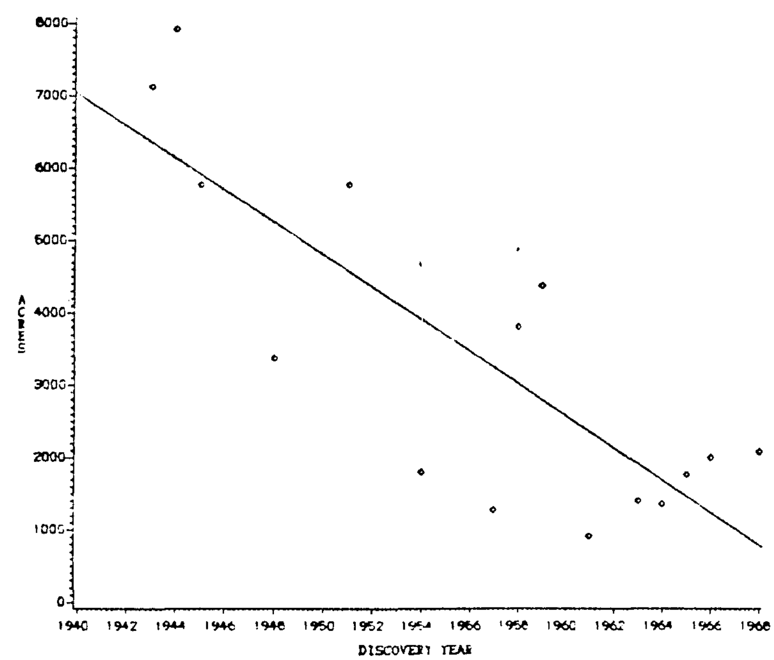


Figures A.20a and A.20b

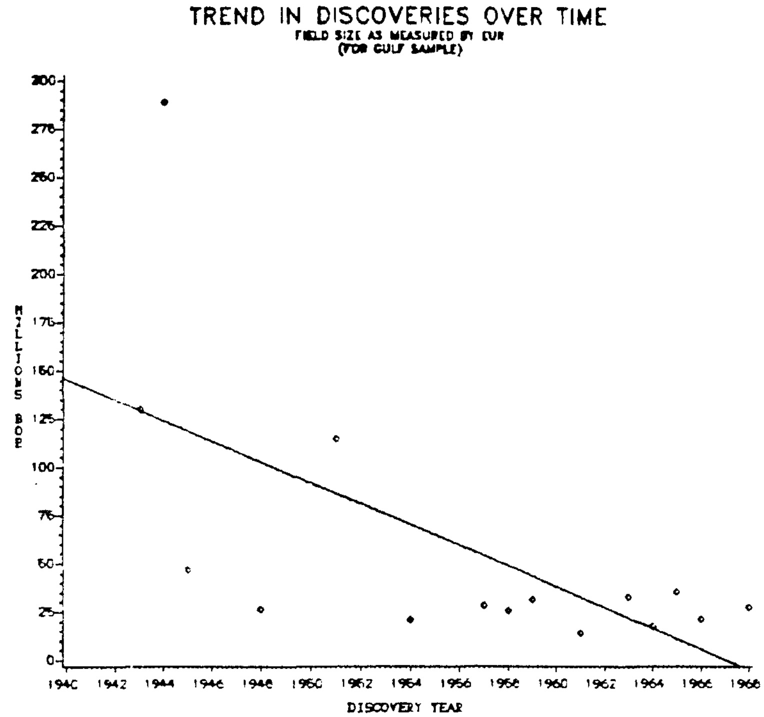
TREND IN DISCOVERIES OVER TIME
FIELD DEPTH
(FOR GULF SAMPLE)

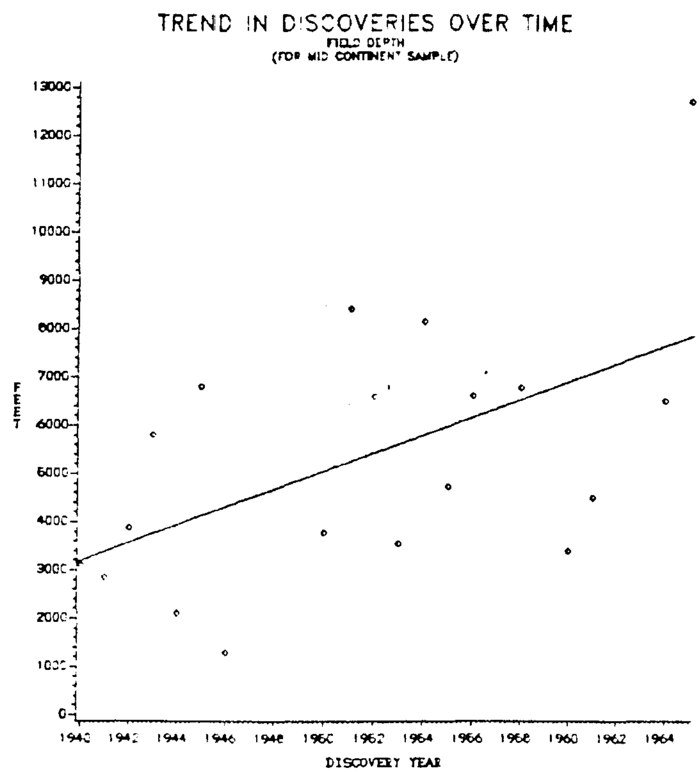


TREND IN DISCOVERIES OVER TIME
FIELD SIZE AS MEASURED BY SURFACE ACREAGE
(FOR GULF SAMPLE)

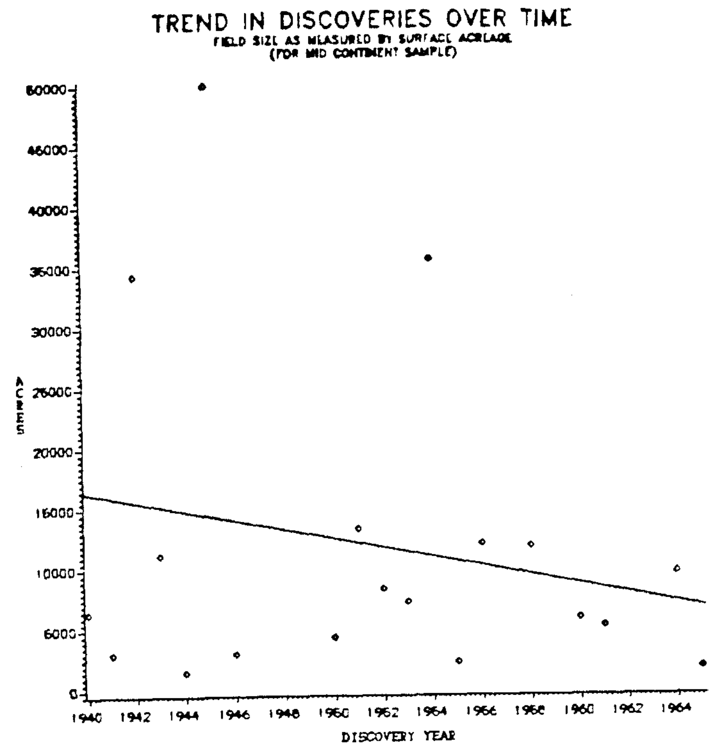


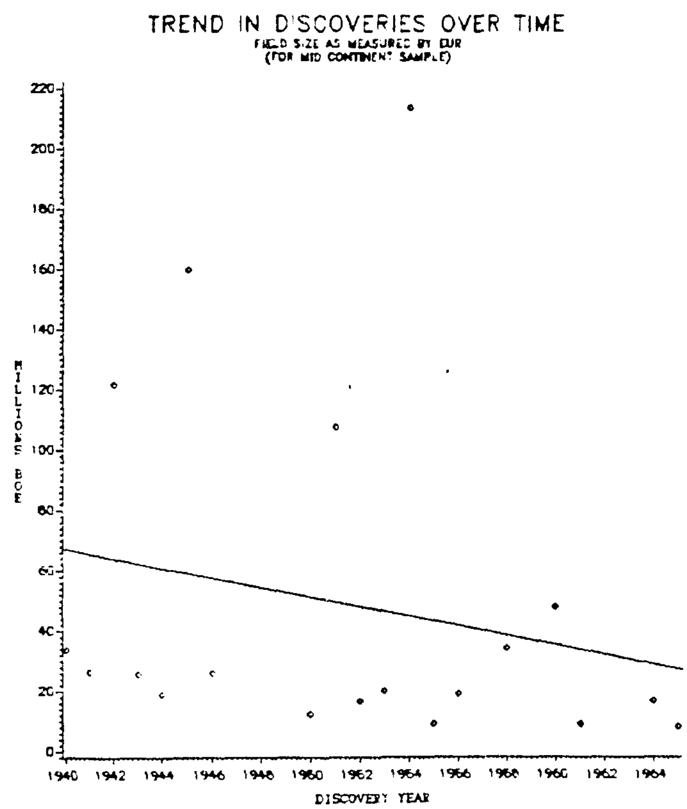
Figures A.21a and A.21b



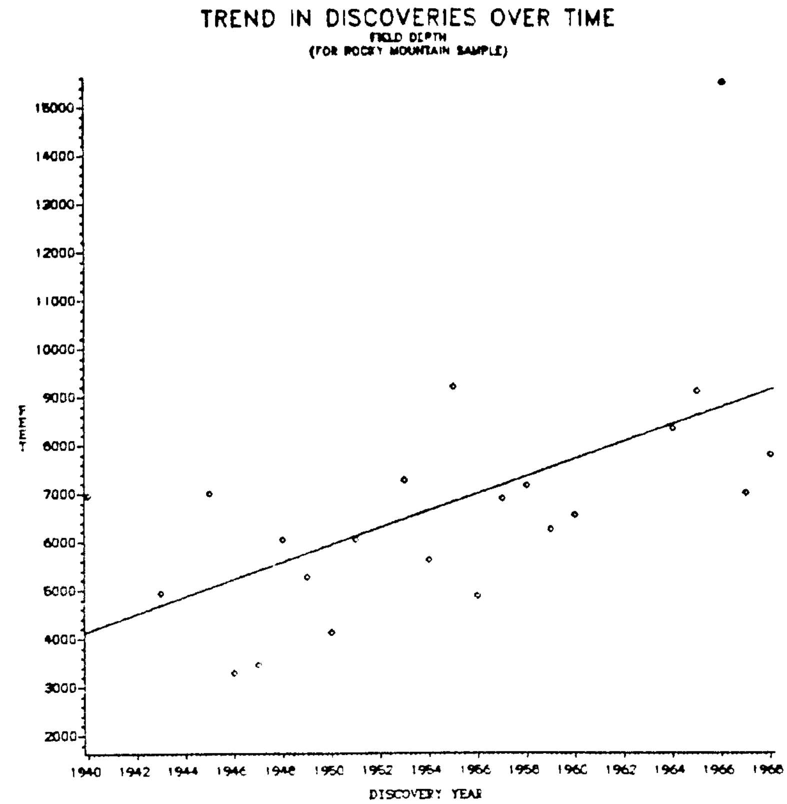


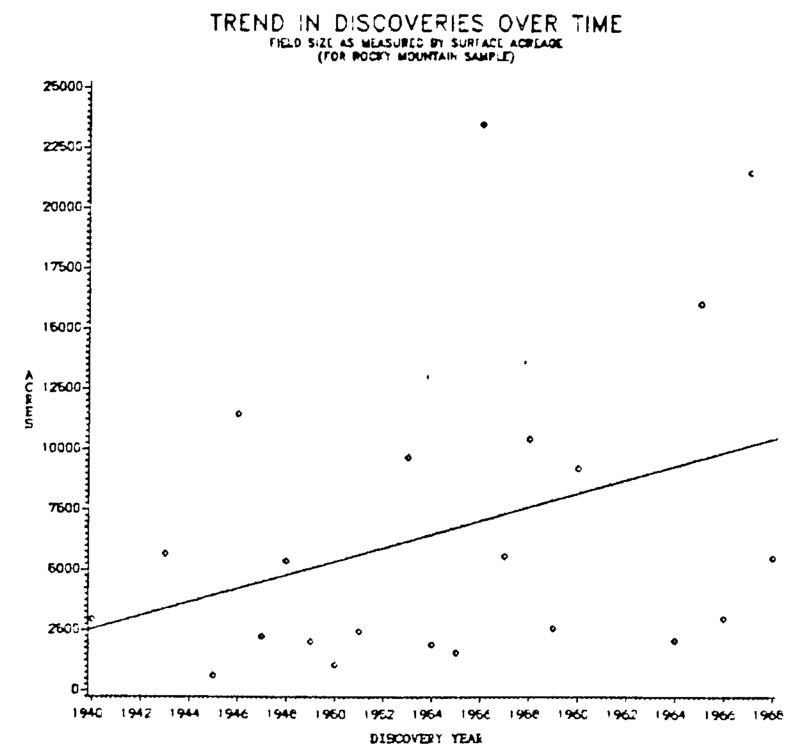
Figures A.21c and A.22a





Figures A.22b and A.22c





Figures A.23a and A.23b

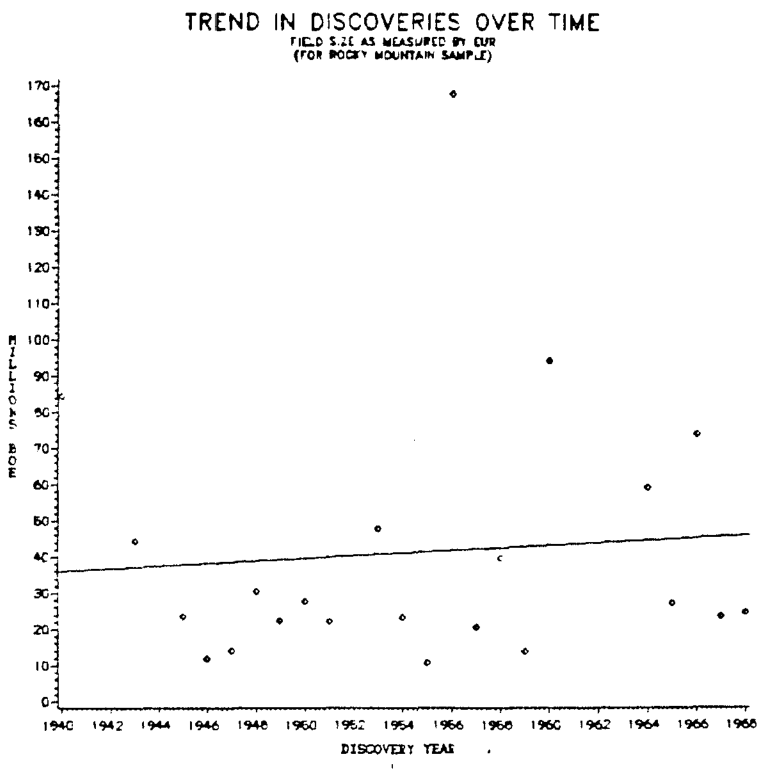

TREND IN DISCOVERIES OVER TIME
FIELD SIZE AS MEASURED BY EUR
(FOR ROCKY MOUNTAIN SAMPLE)
MILLIONS BOE
DISCOVERY YEAR

Figure A.23c

Vita

John D. Grace was born September 9, 1954 in Washington, D.C. He attended public school in Fairfax County, Virginia, and was graduated from J.E.B. Stuart High School in 1972. He recieved a Bachelor of Arts in Russian Area Studies from Louisiana State University in 1975 and a Master of Science in Economics from L.S.U. in 1981.

After receiving his B.A., he taught Russian language and U.S. History in high school in Virginia. In 1978 he worked on the evaluation of geopressured/geothermal resources in Louisiana for the Energy Programs Office at L.S.U. In 1980 he began research on the economics of oil field production under a fellowship from the Louisiana Mining and Mineral Resource and Research Institute.

Between 1981 and 1983, he taught Principles of Economics and Field Geology as a graduate teaching assistant. During the 1983-1984 academic year, he held the position of Senior Research Associate at the Center for Energy Studies at L.S.U. There he conducted research on drilling cost and prepared an evaluation of the oil and gas exploration and production potential of the U.S.S.R for the U.S. Geological Survey.

EXAMINATION AND THESIS REPORT

Candidate: John D. Grace

Major Field: Economics

Title of Thesis: The Habitat and Cost of Production of Domestic Petroleum Resources

Approved:

Herman E. Daly

Major Professor and Chairman

William Payne

Dean of the Graduate School

EXAMINING COMMITTEE:

Adrienne McElwain

Timothy A. Doyle

George F. Hart

Walter R. Whitehead

W. Patton Culbertson Jr.

[illegible]

Date of Examination:

August 27, 1984